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NUREG-0887
Supplement No. 7

Safety Evaluation Report

related to the operation of
Perry Nuclear Power Plant,
Units 1 and 2

Docket Nos. 50-440 and 50-441

Cleveland Electric Illuminating Company

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U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

November 1985

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ABSTRACT

Supplement No. 7 to the Safety Evaluation Report (NUREG-0887) on the application filed by the Cleveland Electric Illuminating Company on behalf of itself and as agent for the Duquesne Light Company, the Ohio Edison Company, the Pennsylvania Power Company, and the Toledo Edison Company (the Central Area Power Coordination Group or CAPCO), as applicants and owners, for a license to operate the Perry Nuclear Power Plant, Units 1 and 2 (Docket Nos. 50-440 and 50-441), has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in Lake County, Ohio, approximately 35 miles northeast of Cleveland, Ohio. This supplement reports the status of certain issues that had not been resolved at the time of publication of the Safety Evaluation Report and Supplement Nos. 1 through 6 to that report.

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ABBREVIATIONS

ADS	automatic depressurization system
ALARA	as low as reasonably achievable
ANI	American Nuclear Insurers
ANSI	American National Standards Institute
ASLB	Atomic Safety and Licensing Board
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient(s) without scram
BMEP	brake mean effective pressure
BNL	Brookhaven National Laboratory
BOP	balance of plant
BTP	Branch Technical Position
BWR	boiling-water reactor
BWROG	BWR Owners Group
CAPCO	Central Area Power Coordination Group
CEI	Cleveland Electric Illuminating Company
CFR	Code of Federal Regulations
CNQAP	Change Notice Quality Assurance Procedure
CP	construction permit
CRC	corrosion-resistant cladding
CRD	control rod drive
DAC	distance-amplitude-correction
DBA	design-basis accident
DCRDR	Detailed Control Room Design Review
DG	diesel generator
DLF	dynamic load factor
DOE	Department of Energy
EAL	emergency action level
ECCS	emergency core cooling system
EPG	Emergency Procedure Guideline
EPIA	emergency preparedness implementation appraisal
EQ	equipment qualification
ERIS	Emergency Response Identification System
ESF	engineered safety feature(s)
ESFAS	engineered safety feature(s) actuation signal
ESW	emergency service water
ETE	evacuation time estimate
FEMA	Federal Emergency Management Agency
FPER	Fire Protection Evaluation Report
FR	Federal Register
FSAR	Final Safety Analysis Report
FWLCS	feedwater leakage control system

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GE	General Electric Company
GESSAR	General Electric Standard Safety Analysis Report
GS	General Supervisor
GSE	General Supervisor Engineering
HCU	hydraulic control unit
HED	human engineering discrepancy
HPCS	high-pressure core spray
I&C	instrumentation and control
ID	inside diameter
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
IFTS	inclined fuel transfer system
IGSCC	intergranular stress corrosion cracking
INEL	Idaho National Engineering Laboratory
JIO	justification for interim operation
LLNL	Lawrence Livermore National Laboratory
LOCA	loss-of-coolant accident
LPCI	low-pressure core injection
LPCS	low-pressure core spray
LRG II	Licensing Review Group II
MCPR	minimum critical power rate(s)
MPC	maximum permissible concentration
MSIV	main steam isolation valve
M&TE	measurement and test equipment
NDE	nondestructive examination
NFPA	National Fire Protection Association
NQADM	Nuclear Quality Assurance Department Manager
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
OBE	operation basis earthquake
OD	outside diameter
OL	operating license
PEI	Perry Emergency Instruction
PGCC	power generation control complex
PNL	Pacific Northwest Laboratory
PSI	preservice inspection
PVORT	Pump and Valve Operability Review Team
QA	quality assurance
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RG	Regulatory Guide
RHR	residual heat removal
RPS	reactor protection system
RPV	reactor pressure vessel

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RRS	reactor recirculation system
RV	relief vessel
RV/SV	relief valve/safety valve
SBO	station blackout
SDG	standby diesel generator
SDV	scram discharge volume
SER	Safety Evaluation Report
SPDS	safety parameter display system
SQRT	Seismic Qualification Review Team
SRP	Standard Review Plan
SRV	safety/relief valve
SSER	Supplement to Safety Evaluation Report
SV	safety valve
TDI	Transamerica Delaval, Inc.
TER	Technical Evaluation Report
TMI	Three Mile Island
V&V	verification and validation

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

The Nuclear Regulatory Commission (NRC) Safety Evaluation Report (NUREG-0887) on the application of the Cleveland Electric Illuminating Company (CEI or the applicant) for a license to operate the Perry Nuclear Power Plant (Perry), Units 1 and 2, was issued in May 1982. Supplements to the Safety Evaluation Report (SER) were issued as follows:

- Supplement No. 1 in August 1982
- Supplement No. 2 in January 1983
- Supplement No. 3 in April 1983
- Supplement No. 4 in February 1984
- Supplement No. 5 in February 1985
- Supplement No. 6 in April 1985

The purpose of this Supplemental Safety Evaluation Report (SSER No. 7) is to further update the SER by providing the results of the staff's review of information submitted by the applicant by letter addressing the issues listed in Sections 1.9, 1.10, and 1.11 of the SER that were not resolved at the time SSER No. 6 was issued. The information provided in those letters must be acceptably documented in amendments to the Perry Final Safety Analysis Report (FSAR) by the applicant before licensing.

Each section or appendix of this SSER is designated and titled so that it corresponds to the section or appendix of the SER that has been affected by the staff's additional evaluation and, except where specifically noted, does not replace the corresponding SER section or appendix. Appendix A is a continuation of the chronology of correspondence between the NRC and the applicant that updates the issues listed in the SER and SSER Nos. 1 through 6. Appendix B is a list of references cited in this supplement.* Appendix E is a list of the principal contributors to this SSER. Appendix G is a further list of errata to the SER and its supplements. Appendices N, O, P, and Q are being added by this supplement. No changes were made to Appendices C, D, F, H, I, K, L, or M.

In addition to updating the status of unresolved issues, this supplement

(1) documents the technical basis on which the applicant's request for an exemption from the provisions of 10 CFR 50 Appendix J, Paragraph III.D.2(b)(ii) is being granted relative to containment airlock testing--the exception applies if no maintenance is performed in the airlock seals. The staff's evaluation finding relative to containment leakage testing has also been updated as it relates to testing of feedwater system isolation valves (see Section 6.2.6)

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*Availability of all material cited is described on the inside front cover of this supplement.

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(2) grants the applicant's request to substitute the General Electric Fuel Surveillance Program for the postirradiation surveillance program previously found acceptable by the staff and documented in the SER (see Section 4.2.4.3)

(3) updates the testing requirement for assuring the reliability of the Transamerica Delaval, Inc. (TDI) diesel generators used for standby emergency power at the plant in the event of a loss of offsite power (see Section 8.3.1)

(4) documents the staff's evaluation findings relative to fire protection items and additionally requested 10 CFR 50 Appendix R deviations identified during onsite plant implementation audits, updating evaluation inputs contained in prior SER supplements (see Section 9.5)

(5) documents the staff's evaluation findings concerning CEI's conformance with ATWS-required actions defined in NRC Generic Letter 83-28 (see Section 7.2.2.3)

(6) updates the staff's findings relative to the applicant's commitment to conform with RG 1.118, response time testing/lifting of leads to perform surveillance testing (see Section 7.2.2.6)

(7) documents the staff's acceptability of the Licensing Review Group II program for ensuring the operability of ECCS deep draft pumps as it pertains to Perry--LRG II Generic Issue 9RSB (see Section 6.3.1.3)

(8) updates the staff's evaluation findings relative to CEI's conformance with the postaccident sampling provisions of TMI Action Plan Item II.B.3 based on modifications proposed by the CEI in a letter dated September 6, 1985 (M. R. Edelman to B. J. Youngblood), accepting the proposed modifications (see Section 9.3.2)

(9) documents the staff's evaluation findings deleting the need for CEI to perform a station blackout test, and granting CEI's request to delete main steam isolation valve leakage control system testing during the initial plant startup test program (see Section 14)

(10) updates the staff's evaluation findings reported in SSER No. 5 relative to reactor protection system setpoints and allowable values currently specified in the Perry Unit 1 Technical Specifications as acceptable for plant operation pending completion of the technical assessment committed to by CEI, affirming the adequacy of setpoints and allowable values predicated on the generic findings of the BWR Owners Group Instrumentation Setpoint Methodology Program (see Section 7.2.2.8)

(11) documents the staff's findings from its review of organizational changes reflected in FSAR Amendment 21 concluding the acceptability of those changes as clarified by CEI in a letter dated October 29, 1985, from M. R. Edelman to B. J. Youngblood (see Section 13.1.2)

Copies of this SSER are available for public inspection in the NRC Public Document Room at 1717 H Street N.W., Washington, D.C., and at the Perry Public

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Library, 3735 Main Street, Perry, Ohio. Copies of this SSER are also available for purchase from the sources indicated on the inside front cover of this report.

The NRC Project Manager is John J. Stefano. Mr. Stefano may be contacted by calling (301) 492-7037 or by writing to the following address:

John J. Stefano
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

1.9 Outstanding Issues

In Section 1.9 of the SER, the staff identified 19 outstanding issues that had not been resolved at the time the SER was issued. Issues resolved, added, and/or redefined in SSER Nos. 1 through 6 follow:

- SSER No. 1 - Three outstanding issues were reported as being satisfactorily resolved, and Outstanding Issue (20) was added.

- SSER No. 2 - Three additional outstanding issues were reported resolved; Outstanding Issue (3) was changed to Confirmatory Issue (53); and Outstanding Issue (21) was added.

- SSER No. 3 - One outstanding issue was reported resolved, and Outstanding Issues (22) and (23) were added.

- SSER No. 4 - Three outstanding issues were reported resolved; two issues were reported as being partially resolved; Outstanding Issues (10) and (12) were changed to Confirmatory Issues (56) and (55), respectively; and Outstanding Issue (24) was added.

- SSER No. 5 - Outstanding Issue (4) was changed to License Conditions (27) and (29) regarding the seismic/dynamic qualification portion of this issue and the environmental qualification portion of Outstanding Issue (4) was redefined; Outstanding Issues (12) and (14) were resolved; Outstanding Issue (5) was changed to License Condition (26); and Outstanding Issue (19) was changed to Confirmatory Issue (61).

- SSER No. 6 - Outstanding Issue (24) was changed to Confirmatory Issue (63) relative to TDI diesel generator reliability.

This supplement fully resolves Outstanding Issues (4) and (9); changes Outstanding Issue (7) to License Condition (33); changes Outstanding Issue (8) to Confirmatory Issue (64); and redefines and resolves Outstanding Issue (22) identifying new and reopened fire protection items. The composite status of each issue is indicated below. If the issue is discussed in this supplement, the section in which it is discussed is identified. The remaining Outstanding Issue (21) must be sufficiently resolved before Perry Unit 1 fuel loading, and will be reported in a future SSER supplement.

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Issue	Status	Section
(1) Turbine missile protection	Resolved and added as License Condition (19) in SSER No. 3	---
(2) Seismic system and subsystem analysis	Resolved in SSER No. 1	---
(3) Reactor internals vibration prototype (BWR/6-238 in.) test program	Changed to Confirmatory Issue (53) in SSER No. 2; resolved in SSER No. 4	---
(4) Environmental qualification of equipment important to safety:	Seismic/dynamic qualification of equipment changed to License Conditions (27) and (28) in SSER No. 5; environmental qualification redefined in SSER No. 5 as shown under Issue column; redefined equipment qualification items resolved in this supplement (i.e., items 4a and 4b)	3.11
(a) Notification that all electrical equipment is qualified or submittal of justification for interim operation (JIO) per 10 CFR 50.49(i) for all unqualified equipment		
(b) Certification that all mechanical equipment is qualified and submittal of three qualification files for staff review, or provide JIO		
(5) Inservice testing of pumps and valves	Resolved and changed to License Condition (26) in SSER No. 5	---
(6) Transient and accident analysis for ECCS, over-pressure and operating MCPR	Resolved in SSER No. 1	---
(7) Control room design	Report of April 1985 in-progress audit of Perry Unit 1 Detailed Control Room Design Review issued. Followup audit conducted in September 1985 and discussed herein, changing this issue to License Condition (33)	18.2

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Issue	Status	Section
(8) Mark III containment system (Humphrey issues)	Changed to Confirmatory Issue (64) in this supplement	6.2
(9) Pool dynamic loads	Partially resolved in SSER No. 4; fully resolved in this supplement	6.2.1.8
(10) Containment purge	Changed to Confirmatory Issue (56) and License Condition (24) in SSER No. 4	---
(11) Periodic testing of ADS actuation systems during plant operation	Resolved in SSER No. 2	---
(12) Manual initiation/termination of ESF systems	Changed to Confirmatory Issue (55) in SSER No. 4; resolved in SSER No. 5	---
(13) IE Bulletin 79-27	Resolved in SSER No. 4	---
(14) Control system failures	Resolved in SSER No. 5	---
(15) Fire protection - safe shutdown	Resolved in SSER No. 2; detailed basis for resolution addressed in SSER No. 3	---
(16) Fire protection - PGCC system (CO_2 vs halon) fire suppressant in control room	Resolved in SSER No. 2; detailed basis for resolution addressed in SSER No. 3	---
(17) HPCS skid piping	Resolved in SSER No. 1	---
(18) Interim shift staffing for two-unit operation	Deferred; applies to Unit 2 operation only	---
(19) Emergency plans (onsite)	Changed to Confirmatory Issue (61) in SSER No. 5	---
(20) Standby liquid control system design	Added in SSER No. 1; resolved in SSER No. 3	---
(21) Reanalysis of transients and accidents: development of emergency operating procedures per TMI Action Plan Item I.C.1	Added in SSER No. 2; under staff review	---

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Issue	Status	Section
(22) Fire protection items		
(a) Fire brigade staffing	Resolved in this supplement	13.1.2.5
(b) Gypsum board wall design	Resolved in this supplement	9.5.1.4.1
(c) Unlabeled fire door and multipurpose wall information	Resolved in this supplement	9.5.1.4.1
(d) Automatic suppression additions	Resolved in this supplement	9.5.1.4.2
(e) Fire alarm conformance with NFPA 72D	Resolved in this supplement	9.5.1.5.1
(f) Switchgear room drainage	Resolved in this supplement	9.5.1.6.4
(g) PGCC CO_2 automatic initiation	Resolved in this supplement	9.5.1.6.2
(h) Fire damper failure evaluation	Resolved in this supplement	9.5.1.4.1
(i) Further deviations to 10 CFR 50 Appendix R	Resolved in this supplement	9.5.1.4.2
(j) Penetrations per BTP CMEB 9.5-1	Resolved in this supplement	9.5.1.4.2
(k) Fire Protection Evaluation Report (Rev. 4)	Resolved in this supplement	9.5
(23) FSAR Table 3.2-1 safety-related items list	Added in SSER No. 3; resolved in SSER No. 4	---
(24) TDI diesel generator reliability	Changed to Confirmatory Issue (63) in SSER No. 6	---

1.10 Confirmatory Issues

In Section 1.10 of the SER, the staff identified 49 confirmatory issues that were not fully resolved when the SER was issued. Issues resolved, added, and/or redefined in SSER Nos. 1 through 6 follow:

- SSER No. 1 - Five issues were reported resolved, and Issue (50) was added. (Issue (50) was initially cited as License Condition (8) in SER Section 1.11.)
- SSER No. 2 - Twenty-two issues were reported resolved, Issue (6) was deleted, and Issues (51), (52), and (53) were added.

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- SSER No. 3 - Six issues were reported resolved.
- SSER No. 4 - Nine issues were reported resolved, Issue (35) was reopened, and Issues (54), (55), and (56) were added. Additionally, the staff's acceptable findings relative to the containment annulus concrete design modification and flaws detected in the steel shell weld radiographs were reported (Issue (3)).
- SSER No. 5 - Issues (8), (11), (12), and (55) were reported resolved; Issue (52) was deleted; and Issues (57) through (61) were added.
- SSER No. 6 - Issue (61) was partially resolved and Issues (62) and (63) were added.

This supplement resolves Confirmatory Issues (1), (7), (23), (28), (31), (35), (56), (57), (59), (60), (61), and (62); reopens Confirmatory Issues (41) and (42); and adds Confirmatory Issue (64). If the issue is discussed in this supplement, the section in which it is discussed is identified. Resolution of the remaining confirmatory issues must be accomplished before fuel load of Perry Unit 1 and will be addressed in a future SSER supplement.

Issue		Status	Section
(1)	Piping final stress analysis	Resolved in this supplement	3.6.2
(2)	Containment buckling analysis	Resolved in SSER No. 1	---
(3)	Containment ultimate capacity analysis	Resolved in SSER No. 1; staff's acceptance of the concrete "annulus fix" design modification, and flaws detected in steel shell weld radiographs addressed and resolved in SSER No. 4	---
(4)	Emergency service water tunnel structure analysis	Resolved in SSER No. 1	---
(5)	Vibration monitoring program for BOP systems	Resolved in SSER No. 1	---
(6)	Mark III containment hydrodynamic loads	Deleted in SSER No. 2	---
(7)	Testing safety-relief valves per TMI Action Plan Item II.D.1	Resolved in this supplement	3.9.3.2.1
(8)	IE Bulletin 79-02	Resolved in SSER No. 5	---
(9)	Dual function pipe whip/support restraints	Resolved in SSER No. 2	---

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Issue	Status	Section
(10) Hydrodynamic effect on CRD/HCU	Resolved in SSER No. 4	---
(11) Fuel mechanical fracturing	Resolved in SSER No. 5	---
(12) Fuel assembly damage from external sources	Resolved in SSER No. 5	---
(13) Fuel rod bowing	Resolved in SSER No. 3	---
(14) Overheating of gadolinia fuel pellets	Resolved in SSER No. 4	---
(15) Preservice/inservice inspection programs	PSI program partially resolved in SSER No. 5; fully resolved in this supplement	5.2.5.2
(16) Material surveillance program - reactor vessel (RV) beltline materials	Resolved in SSER No. 2	---
(17) Fracture toughness RCPB materials	Partially resolved in SSER No. 2; added to Technical Specifications and fully resolved in this supplement	5.3.1
(18) HPCS and RCIC initiation per TMI Action Plan Item II.K.3.13	Resolved in this supplement	5.4.1
(19) Isolation of HPCS and RCIC per TMI Action Plan Item II.K.3.15	Resolved in this supplement	5.4.1
(20) Subcompartment pressure analysis	Resolved in SSER No. 3	---
(21) Suppression pool temperature ture limits	Resolved in SSER No. 4	---
(22) Secondary containment penetration leakage	Resolved in SSER No. 2	---
(23) Containment isolation dependability per TMI Action Plan Item II.E.4.2(f)	Resolved in SSER No. 2; reopened in SSER No. 5; resolved in this supplement	6.2.7(3)
(24) Type C test of all ECCS injection valves	Resolved in SSER No. 2	---
(25) ADS logic modification per TMI Action Plan Item II.K.3.18	Resolved in SSER No. 4	---

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Issue	Status	Section
(26) ATWS recirculation pump trip	Resolved in SSER No. 4	---
(27) Modified SDV level monitoring system	Resolved in SSER No. 2	---
(28) HPCS initiation circuitry final design	Resolved in SSER No. 2; site confirmatory audit conducted in April 1985 and issue resolved in this supplement	7.3.2.2
(29) Remote shutdown panel non-safety-grade readouts	Resolved in SSER No. 2	---
(30) RCIC testing procedures	Resolved in SSER No. 2	---
(31) Calibration of relief valve/safety valve (RV/SV) pressure switches (TMI Action Plan Item II.D.3)	Resolved in SSER No. 2; site confirmatory audit conducted in April 1985; resolved in this supplement	7.5.2.1
(32) Accident monitoring per TMI Action Plan Items II.F.1.4, II.F.1.5, and II.F.1.6	Resolved in SSER No. 2	---
(33) Failures in vessel level sensing lines common to control and reactor protection systems	Resolved in SSER No. 2	---
(34) Final valve design setpoint and analysis	Resolved in SSER No. 2	---
(35) Physical separation of redundant electrical systems	Initially resolved in SSER No. 2; reopened in SSER No. 4 on basis of staff onsite audit; finally resolved in this supplement	8.4.4
(36) Documentation or test of 3-hour-fire resistance of gypsum board walls	Resolved in SSER No. 4	---
(37) Light and communication fire protection features	Resolved in SSER No. 3	---
(38) Revision of fire protection standpipe and hose locations	Resolved in SSER No. 3	---
(39) Portable fire extinguisher locations	Resolved in SSER No. 3	---
(40) Watertight curbs in switchgear/diesel generator rooms	Resolved in SSER No. 3	---

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Issue	Status	Section
(41) Design for noble gas effluent monitors per TMI Action Plan Item II.F.1.1	Iniitally resolved in SSER No. 4; reopened in this supplement and information from applicant under staff review	---
(42) Design for sampling and analysis of plant effluents per TMI Action Plan Item II.F.1.2	Initially resolved in SSER No. 4; reopened in this supplement and information from applicant under staff review	---
(43) Leakage surveillance preventive maintenance program per TMI Action Plan Item III.D.1.1	Changed to License Condition (16) in SSER No. 1	---
(44) Radiation/shielding design of IFTS tube	Resolved in SSER No.2	---
(45) Location of plant area radiation monitoring per TMI Action Plan Item II.F.1.3	Resolved in SSER No. 2	---
(46) Training program per TMI Action Plan Item II.B.4	Resolved in SSER No. 2	---
(47) Nuclear section training program	Resolved in SSER No. 2	---
(48) Shift supervisor training per TMI Action Plan Item I.C.3	Resolved in SSER No. 2	---
(49) Verify implementation of equipment control measures in radiation areas per TMI Action Plan Item I.C.6	Resolved in SSER No. 2	---
(50) No load, light load, and test loading of the diesel generators	Resolved in SSER No. 2	---
(51) NSSS vendor review of low-power ascension and emergency operating procedures per TMI Action Plan Item I.C.7	Site confirmatory audit in progress	---
(52) Pilot monitoring of selected emergency operating procedures per TMI Action Plan Item I.C.8	Deleted in SSER No. 5	---

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Issue	Status	Section
(53) Reactor internals vibration prototype (BWR/6-238 in.) test program	Made a confirmatory issue in SSER No. 2; resolved in SSER No. 4	---
(54) Preoperational and periodic testing plans for the two subsystems in the permanent dewatering system	Added in SSER No. 4; site confirmatory audit in progress	---
(55) Labeling LPCI/LPCS injection valve switches to warn operator that inadvertent operation could cause overpressurization	Added in SSER No. 4; resolved in SSER No. 5	---
(56) Containment purge system - details of program to be used to determine purge criteria for life of plant after first refueling cycle, to be submitted 6 months prior to initial fuel load	Added in SSER No. 4; resolved in this supplement	6.2.4
(57) SPDS design requirements per NRC Generic Letter 82-33	Added in SSER No. 5; resolved in this supplement; post-implementation audit required	7.5.2.6
(58) Confirmation that the lowest temperature will be experienced by the limiting materials of the reactor containment pressure boundary under conditions cited in General Design Criterion 51	Added in SSER No. 5; resolved in SSER No. 6	---
(59) Clarifications of changes made in Chapter 17 of FSAR Amendments 13, 14, and 15	Added in SSER No. 5; resolved in this supplement	17.2
(60) Use of meteorology as a part of plant emergency response capability	Added in SSER No. 5; resolved in this supplement	2.3.3
(61) Emergency plans	Added in SSER No. 5; resolution of onsite emergency plan issues reported in SSER No. 6; FEMA findings on offsite emergency preparedness documented in this supplement; changed to License Condition (31)	13.3

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Issue	Status	Section
(62) Resolution of questions related to documentation of preoperational/startup test in Amendments 15 and 16 of the FSAR, Chapter 14 per RG 1.68	Added in SSER No. 6; resolved in this supplement	14
(63) TDI diesel generator reliability	Added as a confirmatory issue in SSER No. 6 and resolved for low-power operation of Unit 1; under staff review for full-power operation of Perry Unit 1	---
(64) Mark III containment (Humphrey) issues	Added as a confirmatory issue in this supplement; under staff review	6.2

1.11 License Conditions

In Section 1.11 of the SER, the staff identified 15 license conditions. These included several issues that must be resolved by the applicant as a condition for issuance of an operating license, and other longer term issues (noted by asterisk) that will be cited in the operating license issued, to ensure that NRC requirements are met during plant operation. Issues resolved, added, and/or redefined in SSER Nos. 1 through 6 follow:

- SSER No. 1 - License Condition (8) was deleted and added to the list of issues in Section 1.10 of the SER as Confirmatory Issue (50), and Confirmatory Issue (43) was made License Condition (16).

- SSER No. 2 - License Condition (17) was added (also listed as Confirmatory Issue (25) in SER Section 1.10) as was License Condition (18). The results of the staff's generic evaluation of License Condition (2) were also presented.

- SSER No. 3 - License Condition (19) was added, the partial findings of the staff's review of information received pertaining to License Condition (4) were reported, and License Condition (4) was redefined.

- SSER No. 4 - License Conditions (20) through (25) were added, and License Condition (1) was rephrased to make it consistent with the statement in Section 2.5.5 of the SER text.

- SSER No. 5 - License Conditions (4) and (18) were deleted; License Condition (13) was redefined; and License Conditions (26), (27), (28), and (29) were added.

- SSER No. 6 - License Condition (10) was modified based on staff's updated review discussed in Section 13.1.2.3 of SSER No. 6; License Conditions (5) and (15) were deleted; and License Condition (29) was redefined.

This supplement (SSER No. 7) deletes License Conditions (2), (3), (6), (9), (11), (12), (15), (17), (20), (22), (23), (27), and (28). The remaining license conditions which follow, including License Conditions (30) and (31) added in this

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supplement, will be documented in the operating license issued for Perry Unit 1 unless committed to by the applicant in the FSAR before licensing or resolved before licensing (the numerical assignation of each condition is retained for reference back to previous SSERs and the initial SER):

(1) Permanent Slope Protection System (SER, Section 2.5.5)

CEI shall finalize the design of a permanent slope protection system (as described in FSAR Section 2.4.5.5.3) if the toe or crest of the 3H:1V bluff of the Lake Erie shoreline erodes and encroaches closer than 250 feet or 115 feet, respectively, to the emergency service water pumphouse. The permanent slope protection system will be constructed if the limits in the FSAR are reached.

(10) Shift Operating Experience (SSER 6, Section 13.1.2.3)

CEI shall ensure that the Perry Unit 1 facility retains a sufficient number of experienced senior reactor operators during the initial stages of facility operation. A licensed senior reactor operator on each operating shift shall have at least 6 months of hot operating experience at a large commercial BWR, including at least 6 weeks of experience at power levels greater than 20% of full-rated power, and also have BWR startup and shutdown experience. This condition shall be effective for a period of one year from fuel loading or completion of the startup test program, whichever occurs later. At that time, the NRC staff will determine whether this condition may be deleted.

(13) Plant Security (SSER 7, Section 13.6)

CEI shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans, including all amendments and revisions made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p), which are part of the license. The plans which contain safeguards information protected under 10 CFR 73.21 are entitled: "Perry Nuclear Power Plant Security Plan," with revisions submitted through May 15, 1985; "Perry Nuclear Power Plant Security Force Training and Qualification Plan," with revisions submitted through November 25, 1981; and "Perry Nuclear Power Plant Safeguards Contingency Plan" (Chapter 8 of the Security Plan), with revisions submitted through January 8, 1982.

(14) Post-Fuel Loading Initial Test Program (SSER 3, Section 14, TMI Action Plan Item I.G.1)

CEI shall complete the Initial Test Program (ITP) set forth in FSAR Chapter 14. Any changes to this program shall be made in accordance with the provisions of 10 CFR 50.59 and shall be reported in accordance with 10 CFR 50.59(b) within one month of the change.

(19) Turbine System Maintenance Program (SSER 3, Section 3.5.1.3.3)

Within 3 years from the date of the operating license, CEI shall submit a turbine system maintenance program based on the turbine manufacturer's calculations of missile generation probabilities. Before review and

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approval of that program by the NRC staff, CEI will volumetrically inspect all low-pressure rotors at the second refueling outage and every alternate outage thereafter, and conduct turbine steam valve maintenance in accordance with the staff's recommendations.

(24) Containment Purge Criteria (SSER 4, Section 6.24)

CEI shall carry out the three programs described in letters PY-CEI/NRR-0157L dated February 19, 1985 (M. R. Edleman to B. J. Youngblood) and PY-CEI/NRR-0210L dated March 26, 1985 (M. R. Edelman to B. J. Youngblood). Purge criteria to be used for the remainder of plant life, based on the results of these three programs, will be proposed to the NRC before startup from the first refueling outage.

(25) Inservice Inspection Program (SSER 4, Section 6.6.3)

CEI shall submit the initial inservice inspection program required by 10 CFR 50.55(a) for NRC staff review and approval within 6 months from the date the operating license is issued.

(29) RG 1.97, Rev. 2 (SSER 6, Section 7.5.2.2)

CEI shall follow industry development of Category I neutron flux monitoring instrumentation, evaluate newly developed equipment, and notify NRC of plans to install Category I instrumentation when a suitable instrument becomes available. CEI shall provide the staff with information related to the upgrading of the neutron flux monitoring to seismic Category I before plant startup following the second refueling outage.

(30) Detailed Control Room Design Review (SSER 7, Section 18.2)

(a) Before exceeding 5% of thermal-rated power, CEI shall provide, for NRC staff review and approval, the results of human factors surveys of communication/sound in the control room and at the remote shutdown panel; the results of the augmented process for verifying that improvements do not introduce new human engineering discrepancies; and implementation schedules for correcting human engineering discrepancies in accordance with commitments made in CEI letter PY-CEI/NRR-0357L, dated October 2, 1985 (M. R. Edelman to B. J. Youngblood).

(b) Before startup for the second operating cycle, CEI shall implement corrections to human engineering discrepancies in accordance with commitments made in the DCRDR summary reports submitted by CEI letter PY-CEI/NRR-0167L dated January 10, 1985 (M. R. Edelman to B. J. Youngblood) and letter PY-CEI/NRR-0357L dated October 2, 1985 (M. R. Edelman to B. J. Youngblood), and the staff's evaluation findings documented in Section 18.2 of SER Supplement No. 7 (NUREG-0887) issued October 1985.

(c) Before startup for the second operating cycle, CEI shall provide, for NRC staff review and approval, the results of the final human factors sound surveys in the control room and at the remote shutdown panel.

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(31) Emergency Plans (SSER 7, Section 13.3)

(a) In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule (44 CFR 350) is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provisions of 10 CFR 50.54(s)(2) will apply.

(b) Before exceeding 5% of rated thermal power, CEI shall submit letters of agreement obtained from all school districts for the supply of buses for evacuation purposes.

(c) Before exceeding 5% of rated thermal power, CEI shall complete training of fire personnel in monitoring and decontamination procedures and ensure that all reception centers are provided with the necessary decontamination equipment.

1.13 Nuclear Waste Policy Act of 1982 (P.L. 97-425)

This section was added to the SER in SSER No. 4 requiring, as a license condition, that the applicant have in place a contract, or be negotiating a contract in good faith, with the Secretary of Energy for the disposal of nuclear waste as legislated in Section 302(b) of the Nuclear Waste Policy Act of 1982. By letter dated September 3, 1985 (M. R. Edelman to B. J. Youngblood), the applicant transmitted a copy of the contract executed with the Secretary of Energy (Contract No. DE-CR01-85RW00046, effective July 31, 1985). Consequently, the applicant has satisfied SER License Condition (20) which is deleted in this supplement as a condition for Perry licensing.

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2 SITE CHARACTERISTICS

2.3 Meteorology

2.3.3 Onsite Meteorological Measurement Program

In Section 2.3.3 of SSER No. 5, the staff identified Confirmatory Issue (60) related to atmospheric dispersion modeling and use of meteorological information in emergency response. The staff has reviewed Revision 1 to the report entitled, "Description of the Perry Nuclear Power Plant Emergency Offsite Calculations" (NUS-4336), provided by the applicant by letter dated January 4, 1985 (M. R. Edelman to B.J. Youngblood). The staff also participated in the emergency preparedness implementation appraisal (EPIA) conducted February 25, 1985 through March 7, 1985 at the plant site. As a result of these activities, the staff concludes that the applicant has developed and demonstrated a reasonable capability for assessing atmospheric transport and diffusion as part of the dose assessment methodology for emergency response, subject to resolving the concerns identified in the inspection report (NRC Region III Inspection Reports 50-440/85-009 and 50-441/85-007, "Emergency Preparedness Appraisal," dated May 1, 1985) consistent with the goals of the EPIA. Confirmatory Issue (60) is therefore considered to be resolved.

2.4 Hydrologic Engineering

2.4.7 Technical Specifications and Emergency Operation Requirements

In Section 2.4.7 of the SER, the staff stated that a Technical Specification would be required to ensure that the continuing erosion of the southern shore of Lake Erie would not affect safety-related structures over a period of time. The staff now concludes that a Technical Specification is not necessary to ensure the safe operation of the plant. Reasons for the staff's conclusion follow.

Over the past 45 years, the Lake Erie shoreline (toe of bluff) has been eroding and receding toward the plant at an average rate of about 2 ft/year. Section 2.4.3.3 of the SER states that the emergency service water (ESW) pumphouse is the closest safety-related structure to the eroding shoreline. This structure, which is located about 380 feet from the shoreline, could be affected when the shoreline erodes to within 176 feet. Therefore, under average conditions, the ESW pumphouse would not be affected for over 100 years; well beyond the life of the plant.

To mitigate the effects of erosion, the applicant has installed a protection wall along the Lake Erie shoreline. In addition, should erosion continue, the applicant has committed to design and construct a more permanent erosion protection system. Design of this system will be initiated when the shoreline erodes to within 250 feet of the ESW pumphouse and construction will be completed before the toe of the bluff recedes to within 204 feet of the ESW pumphouse. This commitment was made a license condition as discussed in Section 1.11 of the SER.

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The staff concludes that under normal conditions, shoreline protection measures will not be required. However, should the historical erosion rate be exceeded, adequate commitments have been made by the applicant and the aforementioned license condition will ensure that shoreline protection measures are constructed before the ESW pumphouse is endangered. Therefore, the staff concludes that a shoreline-erosion-monitoring Technical Specification is not necessary to ensure safe operation of the plant.

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3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.2 Determination of Break Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

In Section 3.6.2 of the SER, the staff identified a confirmatory item regarding final pipe break locations, pipe whip restraint locations, and jet impingement loads. At that time, the applicant was conducting its piping stress analyses to determine final postulated break locations in high-energy piping systems. The applicant committed to provide the staff the locations of the final postulated pipe breaks and pipe whip restraints in a supplement to its FSAR. In a letter dated June 7, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided the staff the results of its studies. The staff has reviewed the applicant's submittal and finds that the information is sufficiently complete to reasonably conclude that the piping and restraint arrangement for the high-energy fluid systems inside and outside containment will provide adequate assurance that the structures, systems, and components important to safety, which are in close proximity to the postulated pipe breaks, will be protected. Accordingly, SER Confirmatory Issue (1) is considered to be resolved.

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

3.9.2.3 Preoperational Flow-Induced Vibration Testing of Reactor Internals

In Section 3.9.2.3 of SSER No. 4, the staff reported that it had completed its review of GE Topical Report NEDE-22203-P and information provided by the applicant (in Attachment 1 to applicant's letter dated September 9, 1982, D. R. Davidson to A. Schwencer), concluding that the prototype test program proposed by the applicant for Perry was in full conformance with Regulatory Guide 1.20. Receipt by the staff of the final test report was added as License Condition (23) in Section 1.11 of the SER in SSER No. 4. Since the time SSER No. 4 was issued, the applicant has documented a commitment in the FSAR to fully conform to the provisions of Regulatory Guide 1.80 and provide the required report. As such, the staff no longer considers receipt of the test report to be a condition for licensing; therefore License Condition (23) is accordingly being deleted in this supplement.

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.2 Design and Installation of Pressure Relief Devices

3.9.3.2.1 Pump and Valve Operability Assurance

In Section 3.9.3.2.1 of the SER, the staff reported that TMI Action Plan Item II.E.4.2, as it relates to purge and vent valve operability, had not been

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completed by the applicant, and that information provided by the applicant would be addressed in an SER supplement. This item was identified as part of Confirmatory Issue (23) in Section 1.10 of the SER, which encompassed other provisions of TMI Action Plan Item II.E.4.2 concerning containment isolation dependability. In Section 6.2.4 of SSER No. 2, the staff reported its evaluation findings relative to the containment isolation design of the plant, concluding that Confirmatory Issue (23) had been resolved. However, it was later determined that the basis for resolution did not address subitem (f) of TMI Action Plan Item II.E.4.2, as it relates to purge and vent valve operability, and consequently Confirmatory Issue (23) was reopened in SSER No. 5.

At the time SSER No. 5 was issued, the staff and its consultant (EG&G Idaho) were in the process of reviewing supplemental information submitted by the applicant's letter dated December 19, 1984 (M. R. Edelman to B. J. Youngblood), providing information needed by the staff to resolve subitem (f) of TMI Action Plan Item II.E.4.2. The staff's review had also not been completed when SSER No. 6 was issued, and Confirmatory Issue (23) remained unresolved.

The staff has since completed its review of the information presented by the applicant's December 19, 1984 letter and finds that such information demonstrates the ability of the 18-inch and 42-inch purge valves to close against the buildup of containment pressure in the event of a loss-of-coolant accident/design-basis accident (LOCA/DBA), with the condition that the 42-inch valves be limited to a 50-degree opening angle. This valve opening limitation will be specified in the Perry Technical Specifications (see Section 16 of this supplement). The detailed basis upon which the staff has reached this conclusion is in its consultant's Technical Evaluation Report, No. EGG-EA-6828 (March 1985), which is being added to the SER in this supplement as Appendix N.

On the basis of the above related finding, the staff considers Confirmatory Issue (23) to be fully resolved in that the applicant has satisfactorily demonstrated compliance with all applicable provisions of TMI Action Plan Item II.E.4.2.

In Section 3.9.3.2.1 of the SER, the staff reported that it was reviewing the BWR Owners Group test program created to demonstrate General Electric/BWR conformance with the provisions of TMI Action Plan Item II.D.1 pertaining to relief and safety valve operability performance. It was indicated that on the basis of a preliminary review of GE Topical Report NEDE-24988-P, "Analysis of Generic BWR Safety/Relief Valve Operability Test Results," the staff had tentatively concluded that all valves tested were qualified for the low-pressure program test conditions; but that the results of the staff's final review would be addressed in a future SER supplement. This item was accordingly identified as Confirmatory Issue (7) in Section 1.10 of the SER.

The staff has since completed its final review of the BWR Owners Group test program results and the supplemental information provided separately by the applicant by letter dated March 11, 1983 (M. R. Edelman to B. J. Youngblood), and finds that this information demonstrates the ability of the Perry reactor coolant system relief and safety valves to function under expected operating conditions for design-basis transients and accidents, as defined in TMI Action Plan Item II.D.1. In this supplement, the detailed evaluation upon which this finding is based is being added to the SER as Appendix O.

Accordingly, Confirmatory Issue (7) is considered to be fully resolved.

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3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

As part of the review of FSAR Sections 3.9.2 and 3.10, an evaluation is made of the applicant's program for seismic and dynamic qualification of safety-related electrical and mechanical equipment. The evaluation consists of (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general and (2) an audit of selected equipment to develop a basis for the judgment of the completeness and adequacy of the seismic and dynamic qualification program.

Guidance for the evaluation is provided by the Standard Review Plan (NUREG-0800), Section 3.10, and its ancillary documents, RGs 1.100, 1.61, 1.89, and 1.92; NUREG-0484; and Institute of Electrical and Electronic Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies of the seismic qualification of equipment. Conformance with these criteria are required to satisfy the applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100. Evaluation of the applicant's program is performed by a Seismic Qualification Review Team (SQRT), which consists of engineers from the NRC and the Idaho National Engineering Laboratory (INEL) (EG&G Idaho). The INEL report, which provides further details of the audit findings, was added to the SER as Appendix I in SSER No. 5.

The SQRT has reviewed the equipment dynamic qualification information contained in FSAR Sections 3.9.2 and 3.10 and made a visit to the site from August 14 through August 17, 1984. The details of the results of the site audit were discussed in SSER No. 5. There was one equipment-specific item and there were three other programmatic items that required resolution. The applicant, in its letters dated May 29, August 28, and September 23, 1985 (M. R. Edelman to B. J. Youngblood), addressed these issues. The staff has reviewed the information contained in the letters mentioned above, and on the basis of this review, the following resolutions of outstanding issues were obtained.

Equipment-Specific Items

The rod position multiplexer cabinet containing instruments was not qualified as a safety-related equipment item. The staff needed verification that this equipment item was not safety related. In the letter of May 29, 1985, the applicant confirmed that this item is not safety related, and indicated that the basis for the confirmation is documented with the applicant's equipment qualification records in Perry Equipment Qualification (EQ) Book C27. This item is considered to be satisfactorily resolved and is so indicated in the SSER No. 5 Table 3.1, updated in this supplement. This issue is closed.

Programmatic Items

(1) The applicant was required to confirm that all safety-related equipment is fully qualified. The applicant's letter dated August 28, 1985 provided this confirmation. Therefore, this issue is closed.

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(2) The applicant was required to confirm that all safety-related mechanical and electrical equipment subjected to the hydrodynamic loads associated with the pressure-suppression system are capable of withstanding the hydrodynamic loads approved by the NRC. In the letter dated May 29, 1985, the applicant stated that an effort was undertaken to assess that affected equipment is qualified under new hydrodynamic loads. This assessment indicated that the original loads used in tests and analyses to qualify equipment envelope any new loads such as those imposed by the hydrodynamic behavior of the pressure-suppression system or as-built conditions. The staff finds this acceptable. Therefore, this issue is closed.

(3) The staff questioned whether the rod multiplexer cabinet performs any safety-related function. If this function is determined to be safety related, the qualification must be upgraded to the required criteria. As discussed under the equipment-specific item above, it was determined that the rod multiplexer cabinet does not perform any safety function. Thus, the qualification of this equipment item is not affected. The staff finds this acceptable. Therefore, this issue is closed.

On the basis of the discussion above, all the outstanding issues related to seismic and dynamic qualification have been satisfactorily resolved. The staff therefore concludes that the seismic and dynamic qualification program at Perry Unit 1 meets the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100. Consequently, the staff recommends removing proposed License Condition (27) and supports full-power operation from the standpoint of the review reported in Section 3.10.1 of this supplement.

3.10.2 Operability Qualification of Pumps and Valves

The NRC staff performs a two-step review of each applicant's pump and valve operability assurance program to determine whether the applicant's program is adequate to ensure that pumps and valves important to safety will operate when required during the life of the plant under normal and accident conditions. The first step is a review of FSAR Section 3.9.3.2. However, the information provided in this FSAR section is general in nature and, by itself, is not detailed enough to adequately determine the scope of the overall equipment qualification program as it pertains to pump and valve operability. Therefore, in addition to an FSAR review, a Pump and Valve Operability Review Team (PVORT) consisting of engineers from the NRC and the Idaho National Engineering Laboratory (EG&G Idaho) conducts an audit of a representative sample of installed pump and valve assemblies and supporting documentation at the plant site.

This onsite audit is a necessary second step that permits the PVORT to assess the overall program, as implemented, and thereby determine whether the program conforms to the current licensing criteria presented in SRP Section 3.10. Conformance with SRP Section 3.10 criteria is required to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

The PVORT has reviewed the pump and valve operability assurance information contained in FSAR Section 3.9.3.2 and conducted an onsite audit from August 14 through August 17, 1984, to determine the extent to which the pumps and valves important to safety, as installed at Perry Unit 1, meet the criteria described

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above. The details of the results of the site audit were discussed in SSER No. 5. There were three confirmatory items that formed the basis for License Condition (28). In letters dated May 29 and August 28, 1985, the applicant addressed these issues. The staff has reviewed the information contained in the letters mentioned above and, on the basis of this review, the following resolutions were obtained for the outstanding issues:

Confirmatory Items

(1) At the time of the audit many of the preoperational tests had not been completed, and the staff required a confirmation of completion of all necessary preoperational tests before fuel loading. In the letter dated August 28, 1985, the applicant stated that the operability qualification of all safety-related pumps and valves is complete, and made a commitment that required preoperational tests will be completed before fuel load. In the September 23, 1985 letter, the applicant has identified the preoperational testing required to ensure operability that will be performed before fuel loading. This provides unambiguous documentation for the NRC staff to any verification if it is necessary. This is acceptable; therefore, this issue is closed.

(2) The applicant was required to confirm that all pumps and valves important to safety are qualified. As indicated in item (1) above, this was confirmed in the letter dated August 28, 1985. This is acceptable. This issue is closed.

(3) The applicant was required to confirm that the original loads used in tests and/or analyses to qualify pumps and valves important to safety are not exceeded by any new loads such as those imposed by hydrodynamic loads or as-built conditions. In a letter dated May 29, 1985, the applicant indicated that an assessment was performed to reconcile any discrepancy between the qualification level and the actual loading. This assessment confirmed that the original loads were not exceeded. This is acceptable; therefore, this issue is closed.

On the basis of the discussion above, all the outstanding issues on seismic and dynamic qualification of seismic Category I mechanical and electrical equipment and operability of pumps and valves have been satisfactorily resolved, which includes SER License Conditions (27) and (28). The staff concludes that the pump and valve operability assurance program at Perry Unit 1 meets the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, as well as Appendix B to 10 CFR 50. Therefore, the staff recommends the removal of proposed License Condition (28) and supports full-power operation from the standpoint of the review under Section 3.10.2 of this supplement.

3.11 Environmental Qualification of Mechanical and Electrical Equipment

3.11.5 Conclusions

In Section 3.11.5 of SSER No. 5, the staff concluded that the following actions need to be taken by the applicant to resolve the outstanding issue relative to the Perry program for the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment, before Perry Unit 1 licensing:

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(1) Notification that all electrical equipment is qualified or the submittal of justification for plant interim operation in accordance with 10 CFR 50.49(i) for all unqualified equipment; and

(2) Certification that all mechanical equipment is qualified and submittal of three qualification files for staff review and approval, or justification for interim plant operation.

By letters dated August 28 and September 23, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided information stating that all harsh-environment mechanical equipment has been environmentally qualified, and that all equipment within the scope of 10 CFR 50.49 is now qualified, and qualification documentation is available for staff review. Accordingly, SER Outstanding Issue (4) is considered fully resolved for Perry Unit 1 licensing.

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Table 3.1 Equipment audited (revised from Table 3.1 in SSER 5)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status
BOP-1	1OP47C0001B	Control complex chilled water pump	Supplies cooling water for control room chillers			Qualified
BOP-2	1R42S0003	Battery and rack, lead acid electrical storage batteries, and rack that supports the batteries	Provides 225-V dc for the safety systems			Qualified
BOP-3	11M51F0010B	4-in., 300-lb motor-operated globe valve	Provides isolation when shut and throttling when open for the combustible gas control system			Qualified
BOP-4	1D17F0079A	1-in. solenoid valve	Provides containment isolation			Qualified
BOP-5	OH51P0077A	Emergency service water traveling water screen control panel	Controls the traveling screen			Qualified
BOP-6	1R24S0032	Motor control center	Provides 480-V dc and 125-V dc to 1E electrical equipment			Qualified
BOP-7	1P45C0002	Vertical pump, 41.75 ft long by 11-3/8-in. diameter with drive motor mounted on top	Supplies water to the emergency service water system			Qualified
BOP-8	1M39B0004	Air handling unit	Provides ventilation and cooling air			Qualified
BOP-9	1M51S0002	Power supply panel, electrical cabinet with transformers, magnetic contactor, and switch control rectifier panel mounted inside	Supplies power to a hydrogen recombiner			Qualified
BOP-10	OC41N0415B	Level switch for instrument with dial	Is a part of the standby liquid control system (auxiliary mixing tank level indicator)			Qualified
BOP-11	1R72S0002	Medium voltage modular electrical penetration	Maintains the containment pressure boundary			Qualified

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Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status
NSSS-1	1C71S0003G	Electrical protection assembly	Performs a 1E protection function			Qualified
NSSS-2	1H22P0072	Rod position multiplexer cabinet, a cabinet containing instruments	Transmits correct rod position	GE investigating whether this equipment is safety related or not	Not safety related (see applicant's letter of 5/29/85 (Edelman to Youngblood)	Closed
NSSS-3	1C11F0180	Control rod drive scram discharge volume vent valve	Normally open and required to close when a scram occurs			Qualified
NSSS-4	1C41F0004B	Squib valve, 4.5-in. by 7-in. diameter, electrically triggered explosive valve	Provides an injection pathway for poison into the primary coolant for the standby liquid control system			Qualified
NSSS-5	1E51C0002	Reactor core isolation cooling (RCIC) steam turbine assembly	Drives the RCIC pump providing water to the reactor vessel to maintain inventory during reactor isolation, the control rod drop accidents, and anticipated transients without scram			Qualified
NSSS-6	1H13P0702	Termination cabinet, electrical cabinet containing cable termination hardware	Provides an interface betweem control room circuitry and electrical cables entering the control room			Qualified
NSSS-7	1H13P0680	Control room panel, a panel containing instruments	Is a principal plant control console			Qualified
NSSS-8	1H13P0870	Benchboard, electrical panel with displays, indicators, and switches mounted on it	Provides support for electrical equipment such as displays, indicators, and switches			Qualified
NSSS-9	0G41F0085	10-in. butterfly valve	Open, controls flow; closed, shuts off flow in the fuel pool return line			Qualified

Table 3.2 Summary of audit by Pump and Valve Operability Review Team (revised from Table 3.2 in SSER 5)

Plant ID No.	Description	Safety function	Findings	Resolution	Status
E51-C001	Reactor core isolation cooling pump (NSSS)	Supplies makeup water to reactor vessel during loss of feedwater	a	b	Closed[c]
E21-C001	Low-pressure core spray pump (NSSS)	Supplies makeup water and heat removal	a	b	Closed[c]
E22-F0010	High-pressure core spray (HPCS) valve to condensate storage (NSSS)	Closed, it isolate bypass to condensate storage	a	b	Closed[c]
P47-C001	Control complex chilled-water water pump (BOP)	Supplies chilled water to control complex	a	b	Closed[c]
M51-F0110	Combustible gas control valve (BOP)	Closed, it isolates backup hydrogen purge line	a	b	Closed[c]
E12-F0048	Residual heat removal system heat removal valve (BOP)	Open, it provides low-pressure coolant injection and suppression pool cooling	a	b	Closed[c]
E22-C003	HPCS water leg pump (BOP)	Pressurizes HPCS pump discharge line	a	b	Closed[c]
	All pumps and valves important to safety		a,d,e	b,f,g	Closed[c]

[a]The applicant has not completed all required preoperational tests.

[b]The applicant confirmed, by letter dated May 29, 1985, that all pumps and valves important to safety will have their required preoperational tests completed before fuel load.

[c]The qualification status is considered closed. All outstanding issues are resolved.

[d]The applicant has not completed the qualification of all pumps and valve important to safety.

[e]The applicant has not verified that all new loads are enveloped by those loads originally used to qualify the equipment.

[f]The applicant, by letter dated August 28, 1985, confirmed that all pumps and valves important to safety are qualified.

[g]The applicant, by letter dated May 29, 1985, confirmed that none of the new loads applicable to pumps and valves important to safety exceed those loads originally used to qualify the equipment.

NOTE: NSSS = nuclear steam supply system: BOP = balance of plant.

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4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.1 Fuel System Damage Evaluation

(5) Dimensional Changes

In Section 4.2.3.1(5) of the SER, the staff reported the periodic measurement fuel channel box deflection to be a license condition subject to resolution before startup of the second cycle of operation of Perry Unit 1.

In Section 4.2.3.1(5) of SSER No. 2, it was reported that the staff had reviewed the Licensing Review Group (LRG) II generic position relative to channel box deflection (Generic Issue 3-CPB), which was submitted by D. L. Holtzscher (LRG II Chairman) to H. J. Faulkner (NRC letter dated May 17, 1982), and determined that the surveillance measures proposed by the LRG II, and endorsed by the applicant for Perry in a letter dated September 16, 1982 (D. R. Davidson to A. Schwencer), satisfactorily addressed this license condition. On the basis of this finding, the staff considered License Condition (2) no longer required; however, it was not deleted as a condition in SSER No. 2. In adherence with the staff's prior findings, License Condition (2), cited in Section 1.11 of the SER, is being deleted in this supplement.

4.2.4 Testing, Inspection, and Surveillance Plans

4.2.4.3 Postirradiation Surveillance

In Section 4.2.4.3 of the SER, the staff reported its acceptance of the postirradiation surveillance program submitted by the applicant's letter dated April 21, 1982 (D. R. Davidson to A. Schwencer). By letter dated March 26, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested that the General Electric Co. (GE) fuel surveillance program be substituted for the program previously submitted and accepted. The staff has reviewed the substituted program and finds that the program in question had previously been accepted by the NRC (GE was advised accordingly by letter from L. S. Rubenstein (NRC) to R. L. Gridley (GE) dated June 27, 1984). Consequently, the applicant's request to substitute the staff-approved GE fuel surveillance program is hereby granted.

4.4 Thermal-Hydraulic Design

4.4.4 Thermal-Hydraulic Stability

In Section 4.4 of the SER, the staff required that the Perry operating licenses be conditioned to have the applicant provide a new stability analysis before the start of the second cycle of operation. This was identified as SER License Condition (3) in Section 1.11 of the SER. In addition, because no analysis had been presented for minimum critical power ratio limits, or stability characteristics

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for single-loop operation, the staff required that the plant Technical Specifications not permit single-loop operation until such analysis was submitted to, and approved by, the staff.

The staff has since completed its generic review of the thermal-hydraulic stability of boiling-water reactor (BWR) cores, and concludes that the GE fuel reloads will meet the stability criteria set forth in GDC 10 and GDC 12 provided that the applicant has in place operating procedures and Technical Specifications which are consistent with the recommendations documented in GE Letter SIL-380, "BWR Core Thermal-Hydraulic Stability," Rev. 1, dated February 10, 1985, to ensure detection and suppression of global or local instabilities. The staff has reviewed the proposed Technical Specifications for Perry and finds them to be consistent with the recommendations in the GE letter, as required. Accordingly, SER License Condition (3) is no longer required and is being deleted in this supplement.

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5 REACTOR COOLANT SYSTEM

5.2 Compliance With Code and Code Cases

5.2.5 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory (INEL). The Technical Evaluation Report from INEL is being added to the SER as Appendix Q by this supplement.

This evaluation supplements conclusions in Section 5.2.5 of SSER No. 5, and addresses the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g).

5.2.5.2 Evaluation of Compliance With 10 CFR 50.55a(g)

Review has been completed on the information presented in the FSAR through Amendment 20 dated July 1985, the Perry Unit 1 Preservice Inspection (PSI) Program including revisions through August 7, 1985, and other related correspondence submitted by the applicant. The PSI Program was essentially a completed document when the section containing the reactor pressure vessel (RPV) was submitted on August 28, 1984. The scope of the examinations, procedures, and acceptance criteria are based on the requirements of ASME Code Section XI, 1977 Edition with addenda through Summer 1978. The extent of examination has been determined by the requirements of ASME Code Section XI, 1974 Edition with addenda through Summer 1975. The staff has reached the conclusion that the PSI Program for systems and components with the reactor coolant pressure boundary is consistent with the applicable regulation and Code requirements.

The staff review of the August 28, 1984 letter (M. R. Edelman to B. J. Youngblood) determined that the selection of welds for the RPV examination is consistent with the applicable Code requirements. The applicant's June 3, 1985 letter (M. R. Edelman to B. J. Youngblood) contained an implementation report describing how the preservice examination of the RPV complies with the alternative method presented in Appendix A to Regulatory Guide (RG) 1.150, Revision 1, and a listing of plant-specific areas on the RPV where the Code requirements cannot be met along with a supporting technical justification. The staff concludes the applicant meets the intent of RG 1.150 for boiling-water reactors (BWRs) (1) by qualifying the examination procedures for the detection of service-induced flaws on the inside surface of the vessel, (2) by documenting all areas on the RPV where the PSI requirements, defined in Section XI of the ASME Code, have been determined to be impractical, and (3) by providing a supporting technical justification. On the basis of the above, the staff concludes that the Perry Nuclear Power Plant Unit 1 reactor pressure vessel examination is in compliance with ASME Code Section XI, meets the intent of RG 1.150, Revision 1, and therefore, is in compliance with 10 CFR 50.55a(g)(3).

The applicant's June 3, 1985, letter also contained Revision 3 of the Main Steam System section of the PSI Program. This revision deleted the exclusion of 4.72-inch inside diameter (ID) pipe for steam service based on normal makeup

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for Class 1 systems. The revised exclusion of 3.0-inch-diameter pipe, based on normal makeup flow, is consistent with paragraph IWB-1220 of Code Section XI and is, therefore, acceptable.

In Section 5.2.5.2 of SSER No. 5, the staff addressed the problem of ultrasonic examination of welds in the reactor recirculation system (RRS) with corrosion-resistant cladding (CRC) applied to the pipe ID for corrosion reasons and to the outside diameter (OD) of the pipe for weld shrinkage or concentricity reasons. In letters dated June 3 and June 4, 1985 (M. R. Edelman to B. J. Youngblood), the applicant addressed this issue submitting a report entitled "Baseline Examination of RRS CRC Welds," and included drawings of the ultrasonic testing calibration blocks. The angle beam transducers used during examinations were nominal 45-degree refracted longitudinal wave, 2.25-MHz, dual-element transducers with contoured wedges and roof angles such that the beams were focused on the area of interest. All angle beam examinations were calibrated for a 1/2 V path using 1/4 thickness (T) and 3/4 T side-drilled holes and 10% ID notches. The axial notches were placed in the heat-affected zone adjacent to the toe of the weld in order to obtain the best sensitivity for the greatest area of interest. During perpendicular examinations, scanning was performed using a 1/2 V technique from two sides. During circumferential examinations, the scanning was performed using a 1/2 V technique in two directions along the weld and the weld crown to examine the weld root. All indications with a signal amplitude of 50% DAC (distance-amplitude-correction) at the reference sensitivity were reported. The applicant indicated that electronic noise levels of 5% to 50% prevented recording down to 20% DAC, as was the practice when the RRS welds without CRC were examined with techniques for the detection of intergranular stress corrosion cracking (IGSCC). The staff has reviewed the information provided by the applicant concerning the examination of welds with CRC and concludes that the instrumentation and techniques meet the requirements of Section XI of the Code and are acceptable for the preservice inspection. Limitations to the examination of individual welds with CRC are discussed in this supplement in Appendix Q, Relief Request #6. The staff will continue to evaluate the development of new or improved examination methods for piping susceptible to IGSCC and the staff will provide guidance to BWR owners on augmented inservice inspection requirements on a generic basis in future documents.

5.2.6 Reactor Coolant Pressure Boundary Leakage Detection

In Section 5.2.6 of the SER, the staff stated that the primary detection methods for unidentified leakage within the drywell included monitoring of floor drain sump flow rate, cooler condensate flow rate increases, and airborne gaseous and particulate radioactivity increases. In FSAR Amendment 18, the applicant downgraded the airborne particulate and gaseous radioactive monitoring methods from primary to supplemental/qualitative methods for determining only high gross unidentified leakage inside the drywell. By letter dated July 22, 1985 (M. R. Edelman to B. J. Youngblood), the applicant stated that the RCPB leakage detection systems for unidentified leakage are in conformance with the RG 1.45, Positions C.2, C.3, C.6, and partially in conformance with Position C.5. However, the entire RCPB leakage detection systems are in conformance with the guidelines of American National Standards Institute (ANSI) Standard ISA-S67.03, since they do not require radioactivity monitoring methods because of their inherent inability to reliably quantify leakage on the order of 1 gpm in 1 hour. The applicant stated that (1) floor drain sump is seismic Category I and its level monitor is Class 1E powered and designed to withstand operation basis

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earthquake (OBE) loads; (2) all monitors are capable of performing their intended functions following seismic events that do not require plant shutdown; and (3) the airborne particulate and gaseous radioactivity monitoring systems are qualified for the safe shutdown earthquake (SSE).

The staff has reviewed the applicant's drawings for both the identified and unidentified RCPB leakage-detection-system monitor locations and finds them acceptable for their intended use. The applicant committed to incorporate the changes identified in the July 22, 1985 letter for RCPB leakage detection methods in a future FSAR amendment.

On the basis (1) of the applicant's meeting the guidelines of ANSI ISA-S67.03 and (2) that the drywell floor drain sump level monitor is Class 1E powered in conjunction with seismic Category I floor drain sump, the staff concludes that the Perry design meets the guidelines of RG 1.45, Positions C.2, C.3, and C.6 by providing alternate leakage-detection systems. The RCPB leakage-detection systems meet the applicable acceptance criteria of Standard Review Plan (SRP) Section 5.2.5 (NUREG-0800).

Requests for relief from ASME Code Section XI requirements which the applicant has determined not practical for Class 1 systems and components were submitted on June 3, 1985 and were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated the ASME Code-required examinations that the applicant determined were impractical and the staff determined that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. On the basis of the review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that the preservice inspection program for Perry Unit 1 is acceptable and in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix Q to this report. Therefore, Confirmatory Issue (15) is considered to be satisfactorily resolved for Perry Unit 1 licensing.

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

5.3 Reactor Vessel Materials, Fabrication, and Integrity

5.3.1 Reactor Vessel Materials

By letter dated August 9, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided reactor vessel material fracture toughness test data and pressure-temperature limit curves for the Perry Units 1 and 2 reactor vessels in response to SER Confirmatory Issue (17). The staff has reviewed this information and finds it acceptable for resolving that confirmatory issue. The pressure-temperature limit curves are being incorporated into the Perry Unit 1 Technical Specifications.

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5.4 Component and Subsystem Design

5.4.1 Reactor Core Isolation Cooling System

TMI Action Plan Items II.K.3.13 and II.K.3.15 address the restart capability of the reactor core isolation cooling (RCIC) system on reactor low water level signal, the potential for separating the RCIC and the high-pressure core spray (HPCS) system initiation levels, and the prevention of inadvertent RCIC trip because of spurious signals.

In Section 5.4.1 of the SER, the staff concluded that the separation of HPCS and RCIC initiation levels is unnecessary, but noted that the applicant was subject to the results of the then-ongoing staff generic evaluation of this topic. It was reported that the applicant had committed to install any required modifications derived from the staff's generic review, at least 4 months before operating licenses were issued for Perry Units 1 and 2, which the staff found acceptable in resolving CEI's compliance with the provisions of TMI Action Plan Item II.K.3.13. However, confirmation of the implementation of the staff-required design was made Confirmatory Issue (18) in the SER.

In Section 5.4.1 of the SER, the staff also concluded that the conceptual design proposed by the applicant to ensure that trips initiated by signals from pressure instruments used to sense flow in the RCIC system, based on continuous high steam flow, was acceptable in satisfying the provisions of TMI Action Plan Item II.K.3.15. However, confirmation of the implementation of the final design deemed acceptable by the staff was made Confirmatory Issue (19) in the SER.

In NRC Inspection Report 440/850055, it was indicated that the applicant had performed the necessary design changes to permit automatic restart of the RCIC system on a reactor low water level signal in accordance with the provisions of TMI Action Plan Item II.K.3.13 acceptable to the staff, and that this feature was successfully verified during the Perry Unit 1 preoperational test program. Consequently, SER Confirmatory Issue (18) is considered to be fully resolved.

NRC Inspection Report 440/850055 also indicated that the applicant had made the necessary changes to incorporate a time delay relay to sense excessively high steam flow/steam supply line breaks in the RCIC system logic to satisfy the provisions of TMI Action Plan Item II.K.3.15, and that this feature was successfully verified during the Perry Unit 1 preoperational test program. Accordingly, the staff considers SER Confirmatory Issue (19) to be fully resolved.

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6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

In Section 6.2 of SSER No. 1, the staff stated that on the basis of a preliminary assessment of the 23 major items (each with related subtopics) identified by Mr. Humphrey (as they affect the Grand Gulf plant), the staff finds that all but two of these issues have either had some prior considerations in the design of the Perry plant or do not represent significant safety concerns. These two items are (1) the effects that structural encroachments over the suppression pool might have on pool swell and impact loads and (2) the response of the residual heat removal system, when it is used in the steam condensing mode, to loads produced by the steam condensation phenomenon.

To resolve the issues identified by Mr. Humphrey, the staff has received letters from the applicant dated September 9, 1982 (D. R. Davidson to A. Schwencer) and January 26, 1983; January 5, 1984; March 19, 1985; June 24, 1985; and September 24, 1985 (M. R. Edelman to B. J. Youngblood), as well as generic related submittals, that provide the analyses or clarifications requested by the staff.

The staff has reviewed the information submitted by the applicant and concludes that all but a few areas have been satisfactorily resolved for Perry. The applicant will provide further information for those few areas, as stated in the applicant's letter dated September 24, 1985; the staff expects the resolution to those issues to be straightforward. Therefore, on the basis of the information received to date, the staff finds sufficient justification for closing SER Outstanding Issue (8) has been provided and plant operation up to full power is justified.

The details of the staff's review of each of the 66 individual Humphrey concerns will be published in an upcoming supplement to the SER. Accordingly, SER Outstanding Issue (8) is being changed to Confirmatory Issue (64) in this supplement.

6.2.1 Containment Functional Design

6.2.1.8 Pool Dynamic Loads (LRG II Generic Issue 1-CSB)

6.2.1.8.3 Status of Review

Section 6.2.1.8.3 of the SER identified the Mark III LOCA-related pool dynamic loads as an outstanding unresolved issue. The staff has completed its review of the LOCA-related pool dynamic loads, the results of this evaluation are summarized below.

LOCA-Related Hydrodynamic Load Assessment

The Mark III pool dynamic loads were reviewed at the construction permit (CP) stage for Perry Unit 1, and at the preliminary design approval stage for

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GESSAR-238NI. The staff concluded then that the information available was sufficient to adequately define the pool dynamic loads for nuclear plants at the CP stage of licensing. Since the issuance of the GESSAR-238NI SER (NRC, NUREG-75/110, December 1975), GE has conducted further tests and analyses to confirm and refine the original load definitions. To keep the NRC and Mark III applicants apprised of the current status of these tests, GE issued an Interim Containment Loads Report (22A4365) in April 1978 and several revisions to it before the GESSAR II application was provided to the staff in March 1980. The GESSAR II application is GE's final design approval submittal for its standard "nuclear island" design and is to be referenced by the Mark III operating license applicants. Appendix 3B of the GESSAR II application provides the standard pool dynamic load definitions for Mark III containments, and is the basic document used for review by the staff and its consultants.

The applicant has included Appendix 3B of GESSAR II by reference in Appendix 3B of its FSAR submittal. Except as noted below, the applicant has adhered to all analytical techniques, assumptions, methodologies, and concepts contained in Appendix 3B of GESSAR II. Where plant-unique parameters differ from those of the GE standard plant, Perry plant parameters are used.

The staff has completed its review of GE's pool dynamic load definitions and has arrived at a definitive set of hydrodynamic load definitions that can be used by all Mark III containment applicants for operating licenses. The results of this generic review are documented in NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition" (NRC). They are applicable to Perry.

Description of Phenomena

Figure 6.7 (this supplement) shows the sequence of events occurring during a design-basis accident (DBA) and the potential loading conditions associated with these events. Following onset of a postulated LOCA, the drywell pressure increases because of blowdown of the reactor system. Pressurization of the drywell causes the water initially standing in the vent system to be accelerated into the pool, and the vents are cleared of water. During this vent-clearing process, the water leaving the horizontal vents forms jets in the suppression pool and causes water jet impingement loads on the structures within the suppression pool and on the containment wall opposite the vents. During the vent-clearing transient, the drywell is subjected to a pressure differential, and the weir wall experiences a vent-clearing reaction force.

Immediately following vent clearing, an air and steam bubble forms at the exit of the vents. The bubble pressure initially is assumed equal to the current drywell pressure. This bubble theoretically transmits a pressure wave through the suppression pool water and results in loading on the suppression pool boundaries and on equipment located in the suppression pool. As the airflow and steamflow from the drywell become established in the vent system, the initial vent exit bubble expands to equalize the suppression pool hydrostatic pressure. Test results from GE's large-scale pressure suppression test facility show that the steam portion of the flow is condensed, but continued injection of drywell air and expansion of the air bubble results in a rise in the surface of the suppression pool. During the early stages of this process, the pool swells in a bulk mode (i.e., a slug of solid water is accelerated upward by the air). Structures close to the pool surface will experience loads as the rising pool

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surface impacts the lower surface of the structure. In addition to these initial impact loads, these same structures will experience drag loads as water flows past them. Equipment in the suppression pool will also experience drag loads.

After the pool surface has risen approximately 15 feet above the initial pool surface, the thickness of the water ligament has decreased to 2 feet or less, and the impact loads are significantly reduced. This phase is referred to as incipient breakthrough (i.e., the ligament begins to break up). To account for possible nonconservatisms in the test facility arrangement, the staff has determined that the breakthrough height should be set at 18 feet above the initial pool surface.

Ligament thickness continues to decrease until complete breakthrough is reached and the air bubble can vent to the containment free space. The breakthrough process results in formation of an air/water froth and, for load definition purposes, is defined to occur at a height of 19 feet above the initial pool surface. The incipient breakthrough height and the height at which froth loads begin, have been set higher than the maximum prediction from test results to ensure conservatism. Continued injection of drywell air into the suppression pool results in a period of froth pool swell. This froth swell impinges on structures it encounters, but the two-phase nature of the fluid results in loads that are much less than the impact loads associated with bulk pool swell.

When the froth reaches the elevation of the floors on which the hydraulic control units for the control rod drives are located (approximately 27 feet above pool level), the froth encounters a flow restriction, which results in approximately 25% of the unrestricted flow area. The froth pool swell experiences a two-phase pressure drop as it is forced to flow through the available open areas. This pressure differential represents a load on both the floor structures and on the adjacent containment and drywell. The result is a discontinuous pressure loading at this elevation.

As drywell air flows through the horizontal vent system decreases, and the air/water suppression pool mixture experiences gravity-induced phase separation, upward movement of pool water stops and the fallback process starts. During this process, floors and other flat structures experience downward loading, and the containment wall theoretically can be subjected to a small pressure increase. However, this pressure increase has not been observed experimentally.

The DBA pool-swell transient associated with drywell air venting to the pool typically lasts 3 to 5 seconds. Following this, there is a long period of high steam flow through the vent system; available data indicate that this steam will be entirely condensed in the immediate vicinity of the vent exits. For the DBA reactor blowdown, steam condensation lasts for approximately 1 minute. Potential structural loadings during the steam condensation phase of the accident have been observed, and are included in the containment loading specification.

As the reactor blowdown proceeds, the primary system becomes depleted of high-energy fluid inventory with a corresponding reduction of the steam flow rate to the vent system. This reduced steam flow rate leads to a reduction in the drywell/containment pressure differential which in turn results in sequential

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recovering of the horizontal vents. Suppression pool recovery of a particular vent row occurs when the vent stagnation differential pressure corresponds to the suppression pool hydrostatic pressure at that row of vents.

Toward the end of the reactor blowdown, the top row of vents is capable of condensing the reduced blowdown flow and the two lower rows will be totally recovered. As the blowdown steam flow further decreases to very low values, the water in the top row of vents starts to oscillate, causing what has become known as vent chugging. This action results in dynamic loads on the top vents and on the weir wall opposite the upper row of vents. In addition, an oscillatory pressure-loading condition can occur on the drywell and containment walls. Since this phenomenon is steam mass-flux dependent (the chugging threshold appears to be in the range of 10 $lb/sec/ft^2$), it is present for all break sizes. For smaller breaks, it is the only mode of condensation that the vent system will experience.

Shortly after a postulated pipe rupture, the emergency core cooling system pumps will automatically start up and pump condensate water and/or suppression pool water into the reactor pressure vessel. This water floods the reactor core and the water may start to cascade into the drywell from the break (the time at which this occurs depends on break size and location). Because the drywell is full of steam at the time of vessel flooding, the sudden introduction of cool water could cause rapid steam condensation and drywell depressurization. When the drywell pressure falls below the containment pressure, the suppression pool level will depress until the horizontal vents are uncovered, and air from the containment enters the drywell. Eventually sufficient air will be returned through the vents to stabilize the drywell and containment pressures; however, during this drywell depressurization transient, there could be a period when a significant negative pressure acts on the drywell structure. A conservative negative-load condition, therefore, was specified for the drywell design.

Small breaks, defined as breaks not large enough to automatically depressurize the reactor, do not result in bounding pool dynamic loads except for the chugging loads and thermal loading conditions on the drywell and weir walls. Thermal gradient load definitions are provided for in the design of the walls containing the suppression pool.

Pool Dynamic Load Assessment

(A) Generic Load Definition

The staff's review of the generic LOCA-related pool dynamic load definition was completed early in 1984. The results of this review and the staff's evaluation of the pool dynamic load definitions are documented in NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition," which NRC published in August 1984. With only a few exceptions, the staff found the load definitions proposed by GE in Appendix 3B of GESSAR II to be acceptable. A set of acceptance criteria was developed by the staff to cover those areas where the proposed loads were not satisfactory. These were included as Appendix C to NUREG-0978. A brief description of these acceptance criteria is provided below.

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(1) Pool Swell Velocity

Pool swell velocity controls impact and drag loads on the structures between the initial pool surface elevation and the breakthrough elevation. GESSAR II proposes a value of 40 ft/sec at all elevations. The staff requires use of an elevation-dependent value which varies linearly from 0 up to a maximum of 50 ft/sec at elevations greater than or equal to 10 feet above the initial elevation.

(2) Pool Swell Loads on Structures Attached to the Containment Walls

The GESSAR II specification corresponds to steady-state drag at a fixed velocity of 40 ft/sec. The staff's acceptance criteria require this to be modified to reflect the change in pool swell velocity given in item (A)(1) above and the inclusion of impact-type forces when the structure is not immersed prior to pool swell. A detailed procedure for evaluating the impact load is provided in the acceptance criteria.

(3) Bulk Impact on Small Structures

The GESSAR II methodology was found acceptable provided the structures involved satisfied certain limitations related to structural natural frequency, size, and location above the pool. The acceptance criteria require that when any of these limitations are not satisfied, the load specification be reviewed by the staff on a plant-unique basis.

(4) Froth Impact Loads

The GESSAR II methodology was found to be unacceptable. An acceptable alternative was developed by the staff and its consultants and is described in detail in the acceptance criteria. The new method differs from the GESSAR II approach with respect to maximum froth impact pressure, temporal characteristics of the forcing functions, and region of application.

(5) Drag Loads

The GESSAR II methods are found acceptable provided they are modified to account for the change in pool velocity given in item (A)(2) above and provided they correctly account for the structure-wall interaction effect on drag loads.

(6) Loads on Submerged Structures

The GESSAR II methods are acceptable except for computation of acceleration loads on non-cylindrical structures and the evaluation of standard drag during the condensation oscillation phase of the LOCA. The staff requires that the Mark I acceptance criteria as set forth in NUREG-0661 be used to develop these loads.

(7) Impact Loads on Structures Above the Weir Annulus

The GESSAR II methods were found to be acceptable except for radial structures located within 1 foot of the top of the weir wall and all structures located between 0 and 0.25 foot above the weir wall. Detailed procedures for evaluation of the impact loads in these cases are provided in the acceptance criteria.

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(B) Perry Nuclear Power Plant-Unique Load Evaluation

(1) Applicability of the Generic Load Definition

The staff has examined the information supplied in the FSAR and has concluded that the generic load criteria described in NUREG-0978 are applicable to the Perry plant. All major structures and components that would experience LOCA-related pool dynamic loads are within the range of applicability of the staff-approved methodology in terms of geometry and relative location in the containment and the suppression pool. The major features of the suppression pool geometry (main vent submergence and vertical spacing, pool radial width, and pool depth) differ slightly from the standard plant dimensions, but these differences are not considered significant in terms of their effect on pool dynamic loads. The applicant's use of the generic methodology to develop the LOCA-related pool dynamic load definition is, therefore, acceptable to the staff.

(2) Plant-Unique Load Definition

Although the applicant has used the generic load criteria for the majority of structures and components, there are areas where plant-unique loads were developed. For these cases, Brookhaven National Laboratory (BNL) was contracted to assist the staff in the review. The following evaluation reflects the combined review of both the staff and BNL.

(a) Containment Load Due to Pool Swell at the Hydraulic Control Unit Floor (Wetwell Pressurization)

This item corresponds to Section 3B.6.1.6 of Appendix 3B of the Perry FSAR. The GESSAR II methodology requires a ramp-type pressure loading on the containment when froth flows past the HCU floor. The overall pressure differential that is specified is 11 psi as shown in Figure 3B-57 of GESSAR II. The applicant states that the use of a somewhat smaller value of 10 psi was employed for design. The applicant also states that this reduction is justified by plant-unique differences in the containment geometry. Specifically, the Perry hydraulic control unit (HCU) floor is 7 feet higher than the GESSAR II standard, and the open area at the HCU floor is also greater than the standard.

The staff agrees with the applicant that these plant-unique differences will tend to decrease the pressure loading, particularly the increased elevation of the HCU floor. On the basis of this consideration, the staff finds the reduced design load of 10 psid to be acceptable.

(b) Drywell Bubble Pressure and Drag Loads Due to Pool Swell

The applicant's method differs from that recommended by GESSAR II in that the method of images procedure for calculation of pressure differential is replaced by direct application of the LOCA bubble pressure. Since this approach results in larger pressure differentials, the proposed method is more conservative and therefore acceptable.

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(c) Condensation Loads

The applicant does not use the methods of GESSAR II for pipes and RHR strainers. Instead, the applicant claims that the loads on these structures are bounded by the LOCA air bubble loads and the safety/relief valve second pop actuation loads, respectively, for all relevant load combinations. Using the information available in GESSAR II, the staff has independently confirmed that this approach is bounding. Accordingly, this proposed approach is acceptable.

(d) Impact Loads

In the attachments to a letter dated January 31, 1983 (M. R. Edelman to B. J. Youngblood), the applicant indicated that the GESSAR II methods as modified by the Draft Acceptance Criteria (Appendix C of attachment to NRC letter dated October 8, 1982 from T. P. Speis, NRC, to H. Pfefferlan, GE) were the design basis for the class of structures which are affected by the specification. This modification required that, for structures less than 4 feet long, the pulse duration be reduced by a factor x/4, where x is the actual length of the structures; also, for structures closer than 6 feet above the pool surface, the pulse duration was to be reduced by a factor y/6, where y is the actual elevation of the structure above the pool.

Since the Draft Criteria have been superseded by the requirements of Appendix C to NUREG-0978, the applicant has developed a revised evaluation using a methodology that is consistent with staff criteria. The intent was to demonstrate that, for relevant structures, the methods identified in NUREG-0978 produce loads that are less than those originally used for design, thereby verifying its adequacy.

A description of these new methods was presented in an attachment to the applicant's letter dated May 16, 1985 (M. R. Edelman to B. J. Youngblood). The impact loading for each component is to be determined as follows:

(i) Pulse Duration

The impact pulse duration τ(sec) will be determined using the Maise (applicant's May 16, 1985 letter cited above) or the Mark II criteria (NRC, NUREG-0487), whichever is greater.

(ii) Impact Pressure

The impact pressure will be calculated using the hydrodynamic mass of the target which is a function of the target shape (flat or cylindrical) and orientation above the pool (radial or circumferential). The hydrodynamic mass is determined from NEDE-13426-P GE, Figures 6-8 and 6-9, for radial and circumferential orientation, respectively.

The impact velocity as a function of height above the pool is determined using Equation C-1 of the Mark III Acceptance Criteria (NRC, NUREG-0978).

$V = 5H\ (2.6 - 0.506\ \sqrt{H})$ $\quad H \leq 10$ ft
$V = 50$ ft/sec $\quad H \geq 10$ ft

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The total impulse will be calculated using Equation C-4 of NUREG-0978.

I_p = $(M_H/A) * V/(32.2 \times 144)$ = impulse per unit area

M_H/A = hydrodynamic mass per unit area, lbm/ft^2

V = impact velocity, ft/sec

Using the pulse duration τ, the impact pressure will be determined assuming an isosceles triangle loading:

$P = 2 * I_p/\tau$ (psi)

The above impact load and pulse duration will be used to evaluate each component. This evaluation involves the following additional considerations.

(1) A dynamic load factor (DLF) will be evaluated based on the natural frequency of the component. In most cases the DLF used in the original design was the theoretical maximum.

The original design load $(P*DLF)_{orig}$ will be compared to the revised impact load, $(P*DLF)_{rev}$, and found acceptable if, for radial orientation, $P_{orig}/P_{rev} \geq 1.25$ and if for circumferential orientation, $P_{orig}/P_{rev} \geq 2.00$.

(2) For components other than structural beams originally qualified using a dynamic load evaluation, either method (1) will be used for re-evaluation or the dynamic evaluation will be redone using the revised load and a radial $M_H A$.

(3) Components that were originally designed to a lower load will be re-evaluated and qualified on the basis of sufficient margin in the original design.

(4) For structural beams originally qualified using a dynamic load evaluation, a reevaluation will be performed using the Maise criteria.

The staff reviewed this methodology and finds that it conforms in almost all respects to procedural steps previously approved by the NRC staff in NUREG-0487 and NUREG-0661 (essentially the Maise criteria, 1984). Two areas of nonconformance have been identified, however. These are the use of a triangular impulse to represent the impact load and determination of hydrodynamic mass M_H, for circumferentially oriented structures from Figure 6-9 of GE Report No. NEDE-13426-P. The methods approved by the staff require use of a versed sine representation for impulse shape and determination of M_H from Figure 6-8 of NEDE-13426-P for all structures.

Both of the modifications used by the applicant cause a reduction in the derived load. This reduction is estimated to be about from 10% to 25%

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because of the use of a triangular pulse (depending on structural natural frequency) and about 60% because of the use of Figure 6-9 to determine M_H for circumferentially oriented structures. Application of the correct procedures would therefore imply an increase of up to 25% in load for radial targets and doubling of the load for circumferential targets.

However, since these deficiencies will be accommodated either by reevaluation using the actual Maise criteria (method 4 above) or by demonstrating sufficient margin as in method 1, the staff concludes that the procedure employed by the applicant is acceptable.

The applicant also states that impact loads on pool swell deflectors have been developed by utilizing methods derived from the Mark I (NUREG-0661) and Mark III (NUREG-0978) Acceptance Criteria. The staff finds the use of these methods to be acceptable.

(e) Drag Loads

At the request of the NRC staff, the applicant has agreed not to utilize Figure 3B-75 of GESSAR II for abscissa values (ratio a/b) less than unity. This deviation from GESSAR II is not plant unique since it will be required of all Mark III plants. On the basis of this agreement, the staff finds the criteria acceptable.

(f) Loads on Expansive Structures at the Hydraulic Control Unit Floor Elevation

The applicant indicates that the HCU floor has a design pressure differential capability of 10 psid rather than the 11 psid differential imposed by the GESSAR II methodology. The justification for use of the smaller value is identical to that cited in item (B)(2)(a). The staff finds the use of a reduced design load acceptable for the reasons also stated therein.

Conclusion

The staff has completed its review of the LOCA-related pool dynamics for the Perry Nuclear Power Plant and finds the load definitions used by the applicant to be both conservative and acceptable. Therefore, SER Outstanding Issue (9) is considered to be fully resolved.

6.2.4 Containment Purge System

As reported in SSER No. 4, the applicant committed to implement a three-point program to assess the need of the containment purge system and to investigate methods to minimize its use consistent with considerations that radioactive discharges from nuclear plants and radiation exposure to personnel be kept as far below regulation limits as feasible, or as low as reasonably achievable (ALARA). In addition, the staff required that the applicant describe each of the following programs: (1) Containment Purge Operation Data-Gathering Program; (2) Containment Access Management Program; and (3) Interim Guidelines for Perry Containment Purge Operation.

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The applicant provided the required program descriptions by letters dated February 19 and March 26, 1985 (M. R. Edelman to B. J. Youngblood); these are summarized as follows:

(1) Containment Purge Operation Data Gathering Program

The purpose of this program is to determine the benefits of containment purge and the operating time required to obtain those benefits. The Mark III containment design has a significant amount of vital equipment inside the containment. This equipment will require routine inspection, maintenance, and surveillance. Therefore, plant personnel need access into the containment during normal plant operating conditions. To ensure that personnel exposure to airborne radioactivity is within the maximum permissible concentrations of 10 CFR 20, containment purging is necessary.

In order to quantify the actual environmental conditions that plant personnel will experience, a data collection program will be implemented during the first fuel cycle. The data to be collected are categorized by six basic sets of information: (a) required access to the containment enclosure; (b) mode of purge operation in the containment enclosure; (c) radioactivity concentrations and radiation levels inside the containment enclosure; (d) general air quality in the containment enclosure; (e) special plant events/parameters; and (f) general information about the status of the plant. The data will be gathered from instrumentation and from various documents such as plant sample logs, containment access logs, radiation work permits, and operations and surveillance logs. Thus, information will be obtained relative to radioactivity source terms and the capabilities of the containment purge system to control the environment in the containment enclosure.

(2) Containment Access Management Program

The purpose of this program is to evaluate and control occupancy of the containment enclosure on the basis of operating experience. This program will consist of the following three phases: (a) provide plant procedures to control access to the containment enclosure by establishing access criteria and identifying types of activities and enhancements to scheduling; (b) collect data on access to the containment enclosure, including when personnel enter the containment enclosure, why they enter, and how long they stay; (c) evaluate data and provide recommendations about reducing access into the containment enclosure, including consolidating plant activities.

(3) Interim Guidelines for Perry Containment Purge Operation

For the first fuel cycle, the containment purge operational limit is 3000 hours per year, during operating Modes 1 through 3. Grab samples will be taken before personnel enter the containment enclosure. Purge will be initiated when air samples taken from the containment enclosure indicate an iodine concentration at or above the 0.25 MPC (maximum permissible concentration specified in 10 CFR 20). Purging will continue as long as occupied areas benefit from reduced airborne activity (approximately 4 hours), or in the event reoccupation or reactor water cleanup is

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planned, soon enough to warrant leaving the purge system in operation. However, during periods when the containment shell is not occupied, the purge valves will be closed.

The applicant has committed to submit a report to the NRC based on the results of operating during the first cycle (see License Condition (24) listed in Section 1.11 of this supplement, introduced in SSER No. 4). The report will summarize data gathering, apparent trends, and operating procedures. The operational limit for purging the containment will be set at 1000 hours per year for the next fuel cycle. This provision has been incorporated in the Perry Technical Specification that deals with the containment purge system.

The staff finds the program plan, as discussed above, will provide an adequate data base to establish and justify the purge criteria to be used for the remainder of the plant life. Therefore, the staff considers Confirmatory Issue (56) listed in Section 1.10 of the SER to be resolved.

6.2.6 Containment Leakage Testing

Containment air lock testing of primary reactor containment leakage at Perry, Unit 1, is required by Appendix J of 10 CFR 50 and by the plant's Technical Specifications. Paragraph III.D.2(b) of Appendix J details three explicit requirements relevant to the air lock which are to be included in the Technical Specifications.

Paragraph III.D.2(b)(ii) of Appendix J requires that air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than P_a*. Technical Specification 4.6.1.3.b.2 requires only that an overall air lock leakage test be conducted at P_a when maintenance has been performed on the air lock that could affect its sealing capability. Thus, this specification does not fully comply with the testing specified in Appendix J.

By letter dated April 8, 1985, (M. R. Edelman to B. J. Youngblood) the applicant requested an exemption from paragraph III.D.2(b)(ii) of Appendix J for the operating term of the plant. The applicant provided the following discussion to support this exemption request.

Three explicit air lock tests are required by paragraph III.D.2(b) of Appendix J, as stated above. Paragraph III.D.2(b)(i) requires that air locks to the containment enclosure be demonstrated operable by conducting a leak test every 6 months when containment integrity is required by pressurizing the interior of the air lock to P_a (11.3 psig for Perry Unit 1) and verifying that the leakage rate is within its limit. Technical Specification 4.6.1.3.b.1 corresponds to and complies with this portion of Appendix J.

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*P_a is the calculated peak containment internal pressure related to the design-basis accident and specified either in the Technical Specifications or associated bases.

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Paragraph III.D.2(b)(iii) requires an air lock test within 3 days after the air lock has been opened (or at least once every 3 days for openings more frequently than every 3 days) and specifies that an air lock seal test fulfills the 3-day test requirements. Technical Specification 4.6.1.3.a corresponds to and complies with this portion of Appendix J.

The existing air lock doors are so designed that a full-pressure test of an entire air lock at P_a can only be performed after strong "backs" (structural bracing) have been installed on the inner door. This is because the pressure on the inner door during the test is exerted in a direction opposite to the direction of pressure exerted during an accident condition, and the locking mechanisms are not designed to withstand such reverse forces associated with pressures on the order of P_a. Installing strong backs, performing the test, and removing the strong backs, is a cumbersome process requiring at least 12 hours per air lock (there are 2 air locks); during this process, access through the air lock is prohibited. The basic design of the Mark III containment requires frequent access in order to perform surveillance and maintenance activities.

The periodic 6-month test of paragraph III.D.2(b)(i) and the 3-day test requirement of paragraph III.D.2(b)(iii) provide assurance that the air lock will not leak excessively by being opened during shutdown or refueling, assuming that no maintenance has been performed on the air lock and the air lock is properly sealed.

The applicant states that it is advantageous to allow the plant to operate without performing the full-pressure test, since the testing would extend the duration of plant outages by half a day or more several times a year. This would have a significant financial impact on the operation of the plant and these costs would ultimately be passed on to the rate payers.

The staff has evaluated the applicant's requested exemption from paragraph III.D.2(b)(ii). Whenever the plant is in cold shutdown (Mode 4) or refueling (Mode 5), containment integrity is not required. However, if an air lock is opened during Modes 4 and 5, paragraph III.D.2(b)(ii) of Appendix J requires that an overall air lock leakage test at not less than P_a be conducted before plant heatup and startup (i.e., entering Mode 3).

If (1) the periodic 6-month test or paragraph III.D.2(b)(i) and the test required by paragraph 111.D.2(b)(iii) are current, (2) no maintenance has been performed on the air lock, and (3) the air lock is properly sealed, there should be no reason to expect the air lock to leak excessively just because it has been opened in Mode 4 or Mode 5.

Accordingly, the staff concludes that the applicant may substitute the seal leakage test of paragraph III.D.2(b)(iii) for the full-pressure test of paragraph III.D.2(b)(ii) when no maintenance has been performed on an air lock. Whenever maintenance has been performed on an air lock, the applicant must still meet the requirements of paragraph III.D.2(b)(ii). These changes will be reflected in the Technical Specifications.

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Therefore, an exemption from the requirements of paragraph III.D.2(b)(ii) of Appendix J following normal door opening is justified and considered acceptable by the staff for Perry Unit 1, provided that, in lieu of the full-pressure test required by paragraph III.D.2(b)(ii), the applicant performs a seal leakage test in the same fashion as would be required by paragraph III.D.2(b)(iii). If maintenance is performed on the air lock so that the air lock's sealing capability is affected, the applicant shall be required to perform the full-pressure test in accordance with paragraph III.D.2(b)(ii) of Appendix J.

Before granting the exemption discussed above, the staff performed an "Environmental Assessment and Finding of No Significant Impact" pursuant to 10 CFR 50.12 which was published in the Federal Register (50 FR 26862) on June 28, 1985. The applicant was informed of the staff's intent to grant the exemption in the operating license for Perry Unit 1 by letter dated June 21, 1985 (B. J. Youngblood to M. R. Edelman). It was stated in the June 21, 1985, letter that the staff's detailed evaluation pertaining to the exemption would be documented in a future SER supplement. Accordingly, this SER supplement fulfills that intent.

As reported in Section 6.2.6 of SSER No. 2, the staff concluded that the applicant's proposed leak testing program meets the requirements of Appendix J to 10 CFR 50 and is acceptable. However, the design details for the feedwater leakage control system (FWLCS) had not been reviewed before the issuance of SSER 2. The applicant stated that the FWLCS would provide postaccident sealing for both feedwater lines thus precluding the need to perform "Type C" leak testing (Appendix J) of the feedwater isolation valves with an air test medium. The feedwater isolation valve arrangement consists of an inboard (inside containment) check valve, an outboard (outside containment) check valve which is of the same design as the inboard valve, and an outboard remote manual motor-operated isolation valve. Thus, there are three isolation valves in series for each feedwater line which the applicant has proposed to hydrostatically leak test.

The FWLCS is a manually activated system and is estimated by the applicant to be effective within approximately 1 hour after the onset of a LOCA. By letter dated August 30, 1985 (M. R. Edelman to B. J. Youngblood), the applicant has provided sufficient information to demonstrate a water seal would also be maintained by the feedwater system outside the containment during the initial hour after a LOCA. That is, if the feedwater system becomes inoperable during the rapid vessel depressurization following a LOCA, the water within the feedwater piping will begin to flash into the drywell. It is expected that a water seal would remain for a sufficient length of time following the accident until the operator remotely isolates the motor-operated valve. Thus, a water seal would exist in the piping beyond the motor-operated valve.

On the basis of the above, the staff recognizes the existence of a water seal throughout the event to eliminate "valve through leakage." However, leakage can also occur through the valve's stem and packing. To address this concern, the applicant provided a detailed description of the feedwater isolation valves to demonstrate the low probability of leakage occurring in this manner. The staff has reviewed the design of both the feedwater check valve and the motor-operated isolation valve. Regarding the check valve, the staff agrees with the applicant's assertion that the stem leakage is eliminated by a flanged and gasketed bonnet design arrangement. However, for the motor-operated valve, the staff finds that there is a potential for stem leakage. Therefore the staff

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will require a Type C (Appendix J) pneumatic leakage test to be performed on each feed-water motor-operated valve. The check valves may be hydrostatically tested because stem leakage may be considered incredible. The Perry Technical Specifications should be modified accordingly. On the basis of conformance with the above, the staff considers this issue resolved.

6.2.7 TMI-2 Requirements

(1) Rulemaking Proceeding on Degraded Core Accidents (TMI Action Plan Item II.B.8)

In a letter dated June 25, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided a schedule for meeting the requirements of the hydrogen rule in accordance with the provisions of 10 CFR 50.54(c)(3)(vii)(A). By letter dated September 20, 1985 (B. J. Youngblood to M. R. Edelman), the applicant was advised of the staff's acceptance of that schedule. By letter dated September 24, 1985 (B. J. Youngblood to M. R. Edelman), the NRC supplemented its acceptability of the applicant's schedule, requiring that equipment enhancements determined to be necessary based on final analysis, shall be implemented in Perry Unit 1 before startup following the first refueling outage. The operating license will be so conditioned.

6.3 Emergency Core Cooling System

6.3.1 System Description

6.3.1.3 Functional Design

In Section 6.3.1.3 of the SER, it is stated that safety/relief valve (SRV) operability will be demonstrated during plant startups by manually actuating each SRV (including the automatic depressurization system (ADS) valves) one at a time, and observing the turbine bypass valve for change in position. In response to the applicant's request that the staff's position in this regard be clarified (letter from M. R. Edelman to B. J. Youngblood dated May 8, 1985), it is not the staff's intent to actuate the SRVs during the numerous startups that might occur before commercial operation. The test of these valves is only required during the initial startup and subsequent startups following a refueling outage. In-service testing of pumps and valves required according to ASME Code Section XI, and the plant Technical Specifications, will be the final criteria.

By letter dated May 12, 1982 (D. L. Holtzscher to H. Faulkner), the Licensing Review Group (LRG) II provided its initial position on Generic Issue 9-RSB, "Long-Term Operability of Deep Draft Pumps," containing a program for confirming the operability of ECCS deep draft pumps including the HPCS, LPCS, and RHR pumps. By letter dated September 19, 1983 (D. L. Holtzscher to J. J. Stefano), Revision 1 to the May 12, 1982 position on Issue 9-RSB was furnished. Both the initial and revised programs were discussed in meetings between the LRG II and NRC staff on February 24, 1984, and again on June 27, 1985. As a result the staff considers the program proposed acceptable for ensuring the operability of the ECCS deep draft pumps. This finding was transmitted to the LRG II by letter dated July 16, 1985 (B. J. Youngblood to D. L. Holtzscher) informing that each LRG II member was required to formally endorse the accepted program to consider Issue 9-RSB resolved for his respective plant(s). By letter dated

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September 27, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided the required endorsement for Perry Unit 1 and 2.

6.6 Inservice Inspection of Class 2 and 3 Components

This section, prepared with the technical assistance of U.S. Department of Energy contractors from the Idaho National Engineering Laboratory, supplements conclusions in Section 6.6 of SSER No. 5, which addresses the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g).

6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g)

Review has been completed on the information presented in the FSAR through Amendment 20 dated July 1985, the Perry Unit 1 Preservice Inspection (PSI) Program including revisions through August 7, 1985, and other related correspondence submitted by the applicant. The scope of the examinations, procedures, and acceptance criteria is based on the requirements of ASME Code Section XI, 1977 Edition with Addenda through Summer 1978. The extent of examination has been determined by the requirements of ASME Code Section XI, 1974 Edition with Addenda through Summer 1975. The staff has reached the conclusion that the PSI Program for Class 2 and 3 systems and components is consistent with the applicable regulation and Code requirements.

Requests for relief from ASME Code Section XI requirements which the applicant has determined not practical for Class 2 and 3 systems and components were submitted on June 3, 1985 and were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and the staff determined that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. On the basis of review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that the preservice inspection program for Perry Nuclear Power Plant Unit 1 is acceptable in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix Q to this report.

The initial inservice inspection program has not been submitted by the applicant. The program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

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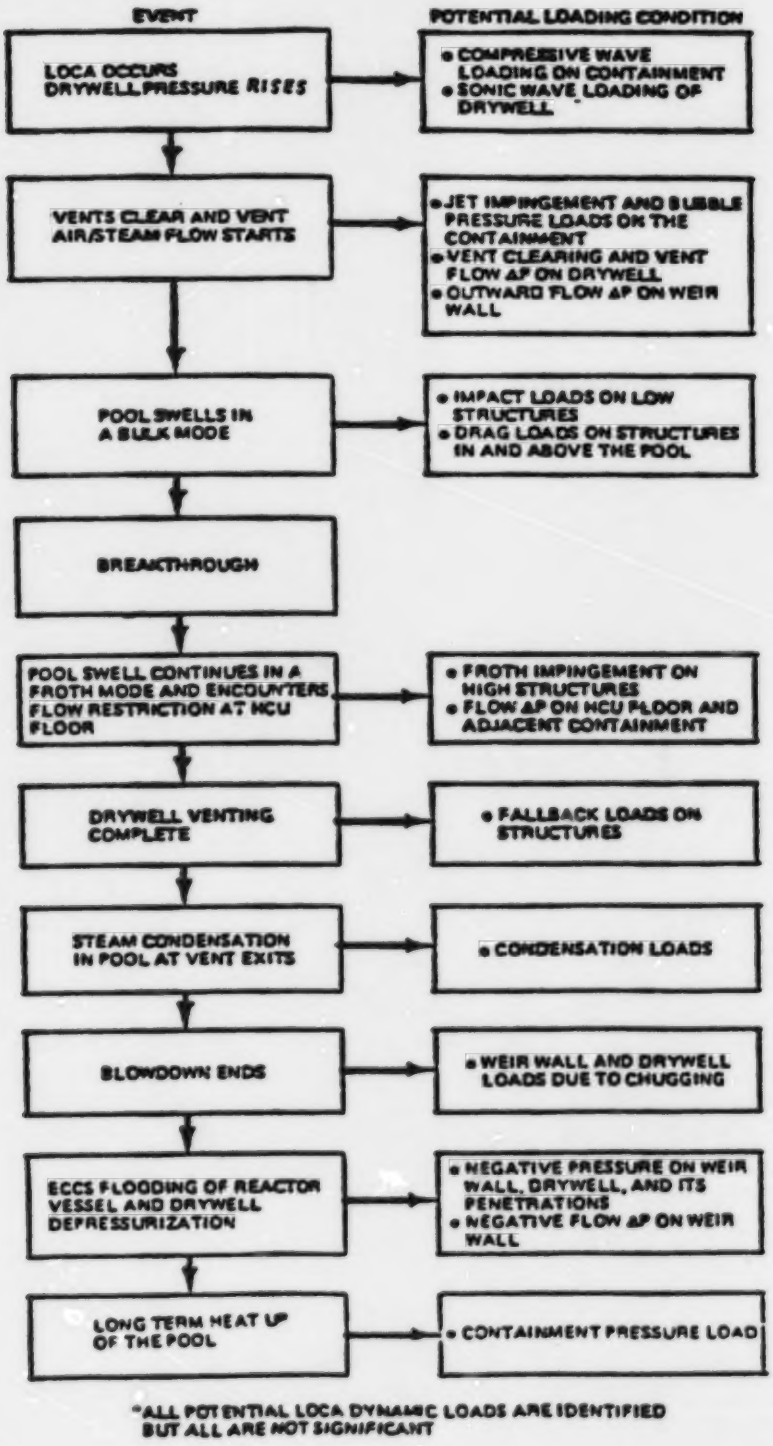
EVENT
POTENTIAL LOADING CONDITION
LOCA OCCURS DRYWELL PRESSURE RISES
• COMPRESSIVE WAVE LOADING ON CONTAINMENT
• SONIC WAVE LOADING OF DRYWELL
VENTS CLEAR AND VENT AIR/STEAM FLOW STARTS
• JET IMPINGEMENT AND BUBBLE PRESSURE LOADS ON THE CONTAINMENT
• VENT CLEARING AND VENT FLOW ΔP ON DRYWELL
• OUTWARD FLOW ΔP ON WEIR WALL
POOL SWELLS IN A BULK MODE
• IMPACT LOADS ON LOW STRUCTURES
• DRAG LOADS ON STRUCTURES IN AND ABOVE THE POOL
BREAKTHROUGH
POOL SWELL CONTINUES IN A FROTH MODE AND ENCOUNTERS FLOW RESTRICTION AT HCU FLOOR
• FROTH IMPINGEMENT ON HIGH STRUCTURES
• FLOW ΔP ON HCU FLOOR AND ADJACENT CONTAINMENT
DRYWELL VENTING COMPLETE
• FALLBACK LOADS ON STRUCTURES
STEAM CONDENSATION IN POOL AT VENT EXITS
• CONDENSATION LOADS
BLOWDOWN ENDS
• WEIR WALL AND DRYWELL LOADS DUE TO CHUGGING
ECCS FLOODING OF REACTOR VESSEL AND DRYWELL DEPRESSURIZATION
• NEGATIVE PRESSURE ON WEIR WALL, DRYWELL, AND ITS PENETRATIONS
• NEGATIVE FLOW ΔP ON WEIR WALL
LONG TERM HEAT UP OF THE POOL
• CONTAINMENT PRESSURE LOAD
*ALL POTENTIAL LOCA DYNAMIC LOADS ARE IDENTIFIED BUT ALL ARE NOT SIGNIFICANT

Figure 6.7 Loss-of-coolant accident chronology (design-basis accident)

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7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Protection System

7.2.2 Specific Findings

7.2.2.3 Anticipated Transients Without Scram

On July 8, 1985, the NRC issued Generic Letter 83-28, entitled "Required Actions Based on Generic Implications of Salem ATWS Events," delineating actions required by the applicant as a result of the anticipated transients without scram that were experienced at the Salem Nuclear Power Plant. The applicant was required to provide plant-specific actions and implementation schedules relative to: (1) post-trip reviews, (2) equipment classification and vendor interface, (3) post-maintenance testing, and (4) reactor trip system reliability improvements.

By letters dated April 6, 1984, August 28, 1985, and September 23, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided the required information on actions to be taken at Perry, and the implementation schedule for completing those actions.

7.2.2.6 Response Time Testing/Lifting of Leads To Perform Surveillance Testing

In a previous Supplemental Safety Evaluation Report (SSER), the NRC staff addressed a concern regarding the degree of conformance to Regulatory Guide (RG) 1.118, Revision 2, "Periodic Testing of Electrical Power and Protection Systems." RG 1.118 provides guidance with respect to periodic testing. On the basis of the staff's review of the applicant's submittal, the staff had determined that the lifting of leads to perform surveillance testing is not in conformance with the recommendations of RG 1.118 and is, therefore, unacceptable without proper justification. Furthermore, the staff found that opening of a fuse and/or breaker to perform a surveillance test would be acceptable only if it satisfies the positions of RG 1.22.

As a confirmatory item, the staff required that the applicant submit a detailed discussion regarding the Perry instrumentation and control (I&C) design's degree of compliance with the guidance of RG 1.118. If the applicant is utilizing wire jumpers, removal of fuses, or the opening of breakers, then their use should be correlated with the various positions (6a and 6b) set forth in the aforementioned regulatory guide. The opening of circuit breakers to perform surveillance testing was also to be discussed within the context of RG 1.22. For the cases that fall outside the guidelines of these regulatory guides, the applicant should modify the design according to the guidelines of these regulatory guides or provide acceptable justification(s) for staff review.

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By letter dated August 20, 1985 from (M. R. Edelman to B. J. Youngblood), the applicant stated that it intends to follow the recommendations of RG 1.118 as closely as practicable in the performance of periodic testing of electric power and protection systems, but the lifting of leads will be required in order to perform a limited number of surveillance tests. The following five categories encompass these exceptions:

(1) A jumper in the form of a test lead, will be utilized to connect a piece of measurement and test equipment (M&TE) to an instrument channel for the purpose of injecting a simulated signal, as permitted by IEEE 338-1977, paragraph 6.4(4).

(2) A jumper in the form of a test lead, will be utilized to connect a piece of M&TE to a channel for the purpose of measuring the output of an instrument, or status of a device, such as for determining relay contact actuation.

(3) A lifted lead or jumper will be utilized to isolate an installed bypass to verify the actual tripping of a device when a permitted bypass condition exists as a result of current operating conditions.

(4) A jumper or lifted lead will be utilized to isolate the channel being tested from other channels to verify end device actuation by the channel being tested when other channels may prevent this determination from being made.

(5) A jumper or lifted lead will be utilized to prevent an actual safety system trip during channel testing, when system design does not provide for the bypass of the channel trip signal.

For each test for which lifting of leads will be required, the applicant committed to follow the guidance provided in IE Information Notice 84-37, "Use of Lifted Leads and Jumpers During Maintenance or Surveillance Testing." IE Information Notice 84-37 recommends a combination of administrative controls and functional tests to verify the restoration of proper system configuration following surveillance tests.

In addition, the applicant stated that breaker operation and fuse removal is necessary to support surveillance testing. However, for these instances, the applicant committed to follow the appropriate guidance in IE Information Notice 84-37. Furthermore, Perry Surveillance Instructions are written with prerequisite conditions which will prevent the expansion of bypass conditions (breaker operation and fuse removals) to redundant or diverse systems. Bypass conditions are controlled through the use of plant tagout procedures, or programmatic controls for control room notification and system restoration in the Surveillance Instruction. Although not automatically indicated to the control room, these administrative controls enable both the Control Room Unit Supervisor, who approves the tagouts prior to the bypass conditions, and the Supervising Operator who is notified in accordance with the Surveillance Instructions to remain cognizant of surveillance tests involving the operation of breakers and fuses.

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On the basis of the results of its review, the NRC staff finds that the combination of administrative controls and functional tests meets the guidelines of IE information Notice 84-37 and provides reasonable assurance that the instrumentation will be restored to the correct configuration following testing where lifting leads or breaker operation/fuse removal is needed. Therefore, the NRC staff finds the actions required acceptable.

As a second part of this confirmatory item, the applicant was required to confirm that response time testing as discussed in RG 1.118 is applicable to both the reactor protection system (RPS) and the engineered safety features (ESF) systems including the sensors where applicable.

By letter dated August 20, 1985 (M. R. Edelman to B. J. Youngblood), the applicant committed to perform response time testing on those portions of both the RPS and the ESF systems as required by the Perry Technical Specifications. The staff found this commitment acceptable and, therefore, this confirmatory item is resolved. However, the staff will verify that the Technical Specifications for Perry include appropriate response time testing for the pertinent RPS and ESF instrument channels including sensors, logic, and actuation devices.

7.2.2.8 Instrumentation Setpoints

During the operating license (OL) review of the Perry Technical Specifications, the staff identified a concern regarding the values selected for protection system instrument setpoints and, in general, the methodology used to establish the reactor protection system setpoints. It was determined that additional information would be required to confirm the applicant's conformance with the Commission's regulations relevant to the issue of protection system setpoints.

The applicable regulations are: General Design Criterion (GDC) 20, 10 CFR 50.36, and 10 CFR 50.46. GDC 20, "Protection System Functions," states that

> The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

10 CFR 50.36 states

> Limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting shall be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded.

10 CFR 50.46 specifies the performance criteria for the emergency core cooling systems. These criteria include a maximum peak cladding temperature, a maximum cladding oxidation, a maximum total amount of hydrogen generated, and requirements that core geometry remain amenable to cooling for long-term decay heat removal. Guidance on acceptable methods for complying with these regulations is contained in RG 1.105, "Instrument Setpoints."

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In an effort to conserve resources and to take advantage of an ongoing review effort, the applicant joined with several other BWR owners that had formed a Licensing Review Group (LRG), Instrument Setpoint Methodology Group (ISMG), so that the requested information could be provided to the NRC. The applicant's commitment to join the ISMG was provided in a letter dated October 9, 1984 (M. R. Edelman to B. J. Youngblood). On July 14, 1983, the NRC staff met with the ISMG at the ISMG request. At this meeting the ISMG presented an outline of a setpoint methodology. In response to additional questions from the NRC staff, another meeting was held on January 31, 1984. By letter dated May 15, 1984 (T. M. Novak to J. F. Carolan), the NRC staff provided its assessment of ISMG methodology. The NRC staff evaluation identified several deficiencies in the methodology presented and requested that the ISMG provide additional information in response to ten specific concerns. In response to the staff's evaluation, by letter dated June 29, 1984 (J. F. Carolan to T. M. Novak), the ISMG provided an action plan for resolving the outstanding issues. By letter dated July 23, 1984 (B. J. Youngblood to J. F. Carolan), the NRC staff accepted the proposed action plan.

On the basis of staff participation in meetings with the ISMG, the work performed by the ISMG and the applicant's commitment noted above, the staff had concluded that this concern would be resolved and the Perry setpoint methodology would be acceptable on an interim basis. This was reported in Section 7.2.2.8 of SSER No. 5.

The applicant was required to document a commitment in the FSAR to provide, for staff review and approval before startup following the first refueling outage, a detailed technical assessment of the methods used to establish the Perry protection system trip setpoints, and allowable values based on the generic findings of the ISMG program. The applicant committed in a letter dated October 17, 1985 (M. R. Edelman to B. J. Youngblood), to document in FSAR Amendment 22 (to be issued before licensing) the detailed technical assessment as discussed above. The technical assessment to be provided will address

(1) The values assigned to each component of the combined channel error allowance (e.g., modeling uncertainties, analytical uncertainties, transient overshoot, response times, trip unit setting accuracy, sensor accuracy, test equipment accuracy, sensor drift, nominal and harsh environmental allowances, trip unit drift), the basis for these values, and the methods used to sum the individual errors. Where zero is assumed for an error, a justification that the error is negligible shall be provided; and

(2) Confirmation that the setpoints selected for the initiation of protective actions ensure that the reactor core and reactor coolant system are prevented from exceeding the licensing safety limits for the transients and accidents analyzed.

The staff finds that sufficient conservatisms are inherent in the safety analyses and the protection system design upon which the Technical Specifications have been developed. The staff further concludes that there is reasonable assurance that the results of the ISMG effort will verify the acceptability of the proposed setpoints and that plant operation in the interim (until the ISMG effort and plant-specific technical assessment are completed) is acceptable. The staff also concludes that instrument uncertainties have been treated properly by the applicant; i.e., the independent uncertainties are combined by the

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root mean square method, whereas the dependent uncertainties are combined algebraically. Moreover, the setpoints used at Perry are consistent with those used at other operating BWR plants.

7.3 Engineered Safety Features Systems

7.3.2 Specific Findings

7.3.2.2 High-Pressure Core Spray System

In Section 7.3.2.2 of the SER, the staff reported that the applicant had requested and the staff had accepted that the high drywell pressure interlock for the HPCS injection valve be removed. The staff accepted this change as it will prevent flooding of the steamline. However, the staff considered the item as confirmatory, based on the applicant's submittal of the HPCS initiation circuitry final design which implements the approved change and its onsite verification that the revised system is installed before plant operation.

During a site audit conducted by the staff in April 1985, the staff confirmed that the revised HPCS initiation circuitry (reflected in plant drawing B-208-065, Rev. 3) had been installed, thereby concluding SER Confirmatory Issue (28) to be resolved. However, during this audit, the staff noted that the logic for the high (Level 8) reactor vessel water level closure of the HPCS injection valve had been incorrectly stated in SSER No. 4 (Section 7.3.2.2). The correct logic for Level 8 trip is one-out-of-two taken twice. In addition, it was determined that to defeat the Level 8 trip, the operator would have to maintain switch S6 in a depressed mode (closed-spring return). This correction and clarification has contributed to the resolution of Confirmatory Issue (28).

A report of the staff's audit findings was transmitted to the applicant by letter dated May 31, 1985 (B. J. Youngblood to M. R. Edelman).

7.3.2.5 IE Bulletin 80-06, "Engineered Safety Features Reset Control" (LRG II Generic Issue 4-ICSB)

As a condition for licensing, the staff required the applicant to review schematic level drawings for all nuclear steam supply shutoff/nuclear boiler systems serving safety-related functions to determine whether or not, upon reset of an engineered safety features actuation signal (ESFAS), the safety-related equipment remains in its emergency mode and to propose corrective action for those items of equipment that do not. Additionally, the applicant was asked to verify by testing that all equipment remains in the emergency mode upon removal of actuating signal and/or manual resetting of the various isolating or actuating signals.

In reviewing the nuclear steam supply system (NSSS), the applicant identified two possible problem areas.

(1) Reactor core isolation cooling/residual heat removal (RCIC/RHR) steam supply valves E51-F063 and F064 change state with reset as follows: Valve E51-F063 will automatically reopen when the Division II RCIC steam isolation signal is reset, if the valve's control switch is left in the open position. Valve E51-F064 will automatically reopen when the Division I isolation signal is reset, if the valve control switch is left in the open position.

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(2) Valve E12-F060A,B, valve E12-F075A,B (RHR sample line valves), and valves B33-F019 and B33-F020 (reactor water sample valves) will reopen upon resetting from an isolation signal if they were open originally.

The applicant agreed to revise the design of these valve control circuits to require operator action to reopen the valve after the appropriate reset button is pushed.

In reviewing the balance of plant (BOP) systems, the applicant identified four systems that were found to have conditions in which equipment did not remain in the emergency mode when the isolation actuation signals were reset. The applicant agreed to revise the design to alleviate the BOP concerns identified in this review.

Upon completion of these design changes, the applicant was required as a confirmatory item to formally submit them for staff review and, in addition, to provide verification that the changes would be implemented before plant operation. Furthermore, as a license condition, the applicant was required to commit to and/or to perform preoperational tests to demonstrate that all equipment remains in its emergency mode upon removal of the actuating signal and/or resetting of the various isolating or actuation signals.

By letter dated May 29, 1985 (M. R. Edelman to B. J. Youngblood), the applicant submitted information that included the applicable drawings regarding the required design changes noted above. In addition, the applicant committed to perform preoperational testing that will demonstrate that all safety-related equipment will remain in its emergency mode upon removal of the actuating signal and/or resetting of the various actuation signals. Furthermore, the applicant stated that this testing would be satisfactorily completed before Perry Unit 1 fuel load.

Upon reviewing the above information and the commitments made by the applicant, the staff concludes that the license condition relating to IE Bulletin 80-06 (engineered safety features reset control) has been satisfied by the applicant. Therefore, License Condition (6), listed in Section 1.11 of the SER, is accordingly deleted.

7.5 Safety-Related Display Instrumentation

7.5.2 Specific Findings

7.5.2.1 Direct Indication of Relief and Safety Valve Position (TMI Action Plan Item II.D.3)

In Section 7.5.2.1 of the SER, the staff reported that the plant reactor coolant system relief and safety valve positions are positively indicated in the control room in accordance with the provisions of TMI Action Plan Item II.D.3 (NUREG-0737). However, verification of the installation and calibration of the pressure switches used for safety/relief valve position indication before plant operation was considered to be a confirmatory matter, and was identified as Confirmatory Issue (31) in Section 1.10 of the SER.

During the staff's site audit in April 1985, a verification and review of the safety/relief valve position indication per TMI Action Plan Item II.D.3 and a

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review of the calibration procedures for the safety/relief valve pressure switches, was conducted. It was determined that the Perry design features a single-channel system per safety/relief valve consisting of a pressure switch which is located at the 620-ft 6-in. elevation on a local instrument rack. This switch is mounted to a sensing line that routes the drywell to the safety/relief valve tailpipe located at elevation 635 ft. The electrical output of the pressure switch is input to the position monitoring electronics. The position monitoring electronics consists of 19 separate cards with five relays mounted on each card. The outputs of these cards are routed to the control room where inputs to annunciators (one per division) and indicators are operated. In addition to the pressure switches, thermocouples are located in the discharge pipe of each safety/relief valve. Temperatures are monitored by a multipoint recorder that provides an alarm upon detecting excessive temperature, signaling that the safety/relief valve seals are leaking.

The staff also reviewed the surveillance instruction for calibrating the pressure switches which showed that the switches are functionally tested and calibrated monthly by simulating a high tailpipe pressure, and verifying by valve status lights and computer points, that the system is functioning properly.

On the basis of these audit findings, the staff has concluded that SER Confirmatory Issue (31) is resolved in that the installation and calibration of safety/relief valve pressure switches conforms with the provisions of TMI Action Plan Item II.D.3.

7.5.2.6 Safety Parameter Display System

By NRC Generic Letter 82-33 (December 17, 1982), all licensees (holders of operating licenses issued by the Nuclear Regulatory Commission) and applicants for an operating license (OL) were required to provide a safety parameter display system (SPDS) in the control room of their plants. The Commission-approved requirements for the SPDS are defined in Supplement 1 to NUREG-0737, which was issued by NRC Generic Letter 82-33.

The purpose of the SPDS is to provide a concise display of critical plant variables to control room operators to help them rapidly and reliably determine the safety status of the plant. NUREG-0737, Supplement 1, requires licensees and applicants to prepare a written safety analysis describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events, which includes symptoms of severe accidents. Licensees and applicants shall also prepare an implementation plan for the SPDS which contains schedules for design, development, installation, and full operation of the SPDS as well as a design verification and validation (V&V) plan. The safety analysis and the implementation plan are to be submitted to the NRC for staff review. The results from the staff's review are to be published in a Safety Evaluation Report (SER) for the respective plants.

Prompt implementation of the SPDS in operating reactors is a design goal of prime importance. The staff's review of SPDS documentation for operating reactors called for in NUREG-0737, Supplement 1, is designed to avoid delays resulting from the time required for NRC staff review. The NRC staff will not review operating reactor SPDS designs for compliance with the requirements of Supplement 1 of NUREG-0737 before implementation, unless a pre-implementation review

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has been specifically requested by licensees. The licensee's safety analysis and SPDS implementation plan will be reviewed by the NRC staff only to determine if a serious safety question is posed or if the analysis is seriously inadequate. The NRC staff review to accomplish this will be directed at confirming (1) the adequacy of the parameters selected to be displayed to detect critical safety functions, (2) that means are provided to ensure that the data displayed are valid, (3) that the licensee has committed to a human factors program to ensure that the displayed information can be readily perceived and comprehended so as not to mislead the operator, and (4) that the SPDS will be suitably isolated from electrical and electronic interference with equipment and sensors used in safety systems. If, on the basis of this review, the staff identifies a serious safety question or seriously inadequate analysis, the Director of NRC's Office of Inspection and Enforcement (IE) or the Director of NRC's Office of Nuclear Reactor Regulation (NRR) may require or direct the licensee to cease implementation.

The staff review for licensees requesting a preimplementation review and for applicants consists of a review of SPDS documentation (i.e., safety analysis report and implementation plan) and audit meetings/site visits.

After an initial review of the licensee's/applicant's submittals, three separate audit meetings/site visits, as described below, may be arranged through the Division of Licensing Project Manager. As dictated by the comprehensiveness of the applicant's/licensee's documentation and the schedule for design and implementation of the SPDS, the objectives of these audits may be met in fewer site visits.

(1) Decision Verification Audit

The purpose of this audit meeting is to obtain additional information required to resolve any outstanding questions about the V&V program, to confirm that the V&V program is being correctly implemented, and to audit the results of the V&V activities to date. At this meeting, the applicant should provide a thorough description of the SPDS design process. Emphasis should be placed on how the applicant is ensuring that the implemented SPDS will provide appropriate parameters, be isolated from safety systems, provide reliable and valid data, and incorporate good human engineering practice.

(2) Design Validation Audit

After review of all documentation, an audit may be conducted to review the as-built prototype or installed SPDS. The purpose of this audit is to ensure that the results of the applicant's/licensee's testing demonstrate that the SPDS meets the functional requirements of the design and to assure that the SPDS exhibits good human engineering practice.

(3) Installation Audit

As necessary, a final audit may be conducted at the site to ascertain that the SPDS has been installed in accordance with the applicant's/licensee's plan and is functioning properly. A specific concern is that the data displayed reflect the sensor signal which measures the variable displayed. This audit will be coordinated with and may be conducted by the NRC Resident Inspector.

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Unlike licensees at operating reactors, applicants will undergo, prior to implementation, a full review to determine whether the applicable provisions of Supplement 1 to NUREG-0737 have been satisfied. To the extent possible, the staff will temper its review to conform to the schedule for licensing and SPDS implementation.

In the case of Perry Nuclear Power Plant, the licensing schedule has affected the staff's review. Because the applicant has installed an SPDS without prior staff approval, the staff has done an operating reactor-style review to determine whether a serious safety question is posed by the Perry design or whether the design analysis is seriously inadequate. The results of that review are documented in this supplement. The staff still intends to perform a full review to determine whether the applicable provisions of Supplement 1 to NUREG-0737 have been satisfied. To that end, an onsite audit will be scheduled as soon as possible after the Perry verification and validation program is complete and the SPDS is fully implemented.

The staff reviewed the SPDS submittals (letters dated March 31, 1983; March 21, 1985; and April 25, 1985, from M. R. Edelman to B. J. Youngblood) for Perry, and concludes that it is acceptable for the applicant to continue implementing its SPDS program. The staff finds the parameter selection for the Perry SPDS to be generally acceptable. The staff had concerns regarding the information density of two of the GESSAR II displays (memorandum dated November 2, 1984, from S. Weiss to C. Thomas). The staff plans to perform an onsite audit and will further review the adequacy of all of the graphic display system displays that provide the SPDS function.

7.5.2.6.1 Evaluation

The applicant sent the staff several letters to review regarding the SPDS for the Perry Nuclear Power Plant, Units 1 and 2 (letters dated March 21, 1983; March 21, 1985; and April 25, 1985, from M. R. Edelman to B. J. Youngblood). The most recent of the applicant's submittals (letter dated April 25, 1985) identified the Perry SPDS as a GESSAR II version of the General Electric Co. (GE) generic SPDS design. Since GESSAR II has been evaluated by the staff, the results reported for GESSAR II in the applicant's March 31, 1983 and March 21, 1985 letters apply to the Perry SPDS as well.

The Perry SPDS is a subsystem of a computer system known as the Emergency Response Information System (ERIS). The SPDS was developed and supplied by GE, and is identical in most respects to the generic GE SPDS that was audited by the staff as part of the GESSAR II Final Design Approval effort (NRC, NUREG-0979, Supplement 4; memorandum dated November 2, 1984 from S. Weiss to C. O. Thomas).

Because the Perry design and the GE generic design are similar, the staff has based the conclusions stated in this supplement on its evaluation of the GE generic prototype (GESSAR II).

Section 4.1.f of Supplement 1 to NUREG-0737 states that:

> The minimum information to be provided shall be sufficient to provide information to plant operators about
>
> (i) reactivity control
> (ii) reactor core cooling and heat removal from the primary system

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(iii) reactor coolant system integrity
(iv) radioactivity control
(v) containment conditions

For review purposes, these five items have been designated as critical safety functions.

The selection of the SPDS process variables for display was made by GE based on the BWR generic Emergency Procedure Guidelines (EPGs). The staff confirmed that the variables selected are consistent with the presently approved BWR EPGs (Rev. 3) with one possible exception. Revision 3 contains a radioactivity release control guideline which contains an entry condition based on offsite radioactivity release rate. The applicant has incorporated enhanced displays to address the radioactivity critical safety function. Therefore, the staff finds the SPDS variable selection generally acceptable, but recommends the addition of variables to represent radiation in the containment vessel. In addition, the staff noted that the design includes sufficient capability for expanding the system so that additional variables (such as hydrogen concentration) may be added as a result of future revisions to the generic EPGs.

The staff reviewed the applicant's submittals to determine that means are provided in the design to ensure that the data displayed are valid. The staff confirmed (NRC, NUREG-0737, Supplement 1) that the validation methodology and the scope of its application in the Perry SPDS does not differ from that used in the generic design audited by the staff (memorandum dated November 2, 1984, from S. Weiss to C. O. Thomas) and, therefore, the staff utilized the results of its audit of the GESSAR II generic SPDS to evaluate the Perry data validation methodology.

Because GE considers its data validation methodology to be proprietary (NRC, NUREG-0979, Supplement 4), a detailed description will not be presented here. Generally, the data validation includes range and consistency checks as well as data-conditioning algorithms.

On the basis of the staff's audit of the GESSAR II SPDS and the similarity between the GESSAR II and the Perry design, the staff confirms that means are provided in the Perry SPDS design to ensure that the data displayed are validated.

The staff evaluated the applicant's submittals for a commitment to a human factors program in the development of the SPDS. As evidence of the applicant's commitment to a human factors program, the staff noted that the applicant has based the Perry SPDS design on the generic GE design which was developed by a multidisciplinary team and included a comprehensive human factors review (NRC, NUREG-0979, Supplement 4). The applicant should ensure that the SPDS developed for Perry by GE has taken into account plant-specific aspects such as color-coding conventions, abbreviations, acronyms, equipment terminology, and symbology.

The staff's review of the GE display formats did identify an area of concern: The "RPV Control" and "Containment Control" displays were too cluttered. In addition, the applicant did not describe the displays used to represent the radioactivity control safety function. The adequacy of these displays will be addressed during the staff's onsite postimplementation audit.

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With the exception of the two issues discussed above, the GESSAR II displays appear to be well designed and are generally consistent with accepted human factors principles. On the basis of the staff's knowledge about the GE design process (NRC, NUREG-0979, Supplement 4; memorandum dated November 2, 1984, from S. Weiss to C. O. Thomas), the staff concludes that an appropriate commitment was made to incorporate human factors considerations into the design of the Perry SPDS.

NUREG-0737, Supplement 1, requires that the SPDS be suitably isolated from electrical or electronic interference with equipment and sensors that are in use for safety systems. The staff audited the GE generic design for adequacy of the isolators (fiber optics cables) and concluded that they are qualified isolation devices and are acceptable for interfacing the SPDS with safety systems (NRC, NUREG-0979, Supplement 4; memorandum dated November 2, 1984, from S. Weiss to C. O. Thomas). Since the Perry design also uses fiber optic cables for isolation (letter from M. R. Edelman to B. J. Youngblood dated April 25, 1985), the conclusions of the staff regarding the GESSAR II SPDS apply.

On the basis of the above review, the staff confirms that the Perry SPDS will be suitably isolated from interference with equipment and sensors that are in use for safety systems.

7.5.2.6.2 Conclusions

The NRC staff reviewed the Perry 1 and 2 submittals to confirm the adequacy of the parameters selected to be displayed to monitor critical safety functions, to confirm that

(1) means are provided to ensure that the data displayed are validated

(2) the applicant has committed to a human factors program to ensure that the displayed information can be readily perceived and comprehended so as not to mislead the operator

(3) the SPDS is suitably isolated

On the basis of its review, the staff concludes that no serious safety questions are posed by the proposed SPDS and, therefore, implementation may continue.

This conclusion is based on the following:

(1) The variables selected for display are generally adequate to assess critical safety functions.

(2) The applicant has stated that the SPDS will be suitably isolated from plant safety systems through the use of fiber optics cables.

(3) The applicant's design provides means to ensure that displayed data are validated.

(4) The design and implementation of the applicant's design includes appropriate commitment to a human factors engineering program that should allow reasonable assurance that the information provided will be readily perceived and comprehended by its users.

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The conclusion that SPDS implementation may continue does not imply staff confirmation that the SPDS meets all of the SPDS requirements of Supplement 1 to NUREG-0737. Such confirmation can be made after a postimplementation review or when the staff has otherwise obtained sufficient information.

The continued implementation of the SPDS by the applicant is conditional to a satisfactory postimplementation onsite audit by the staff.

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8 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power Systems

8.3.1 Alternating Current Power Systems

In Section 8.3.1 of the SER, the staff reported that the applicant had committed to conduct a 20-start-and-load test in addition to the plant preoperational test program as described in Regulatory Guide (RG) 1.108, Position C.2, resulting in a total of 109 tests for the generator units. By letter dated April 25, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested staff approval to eliminate the need for the 20 additional fast-start-and-load-test (10 per diesel engine) tests which were to have been conducted in addition to tests required by RG 1.108 and which were not related to postassembly testing required by the staff for other Transamerica Delaval, Inc. (TDI) diesel generators associated with the need to prove TDI diesel generator reliability.

In SSER No. 6, the staff concluded that the proposed testing per RGs 1.108 and 1.9 was adequate to demonstrate diesel engine operability and to detect abnormal engine behavior. In Appendix M to the SER (introduced in SSER No. 6), Pacific Northwest Laboratory (PNL), the staff's consultant in assuring TDI diesel generator reliability in the wake of the Shoreham Nuclear Plant engine failures, recommended that the 20 additional fast starts not be performed because of the possible deleterious effects on the engines. Previously, on other TDI diesels, PNL had recommended that the following post-reassembly tests be performed after a major disassembly and inspection:

(1) ten modified starts to greater than 40% load

(2) two fast starts to a load greater than or equal to the maximum emergency service loads the engines are predicted to experience, but not greater than a load corresponding to 185 psig brake mean effective pressure (BMEP).

(3) one 24-hour run at a load greater than or equal to the maximum emergency service load the engines are predicted to experience, but not greater than a load corresponding to 185 psig BMEP.

These tests were not intended to duplicate tests required by RGs 1.108 and 1.9, but were to be performed only if not already included in any post-reassembly testing (i.e., as recommended by TDI and/or as required by RG 1.108). In many cases, other than at Perry, preoperational testing per RG 1.108 had been completed before engine disassembly and inspection and the above tests, referred to as post-reassembly tests, were to ensure that the engine had been reassembled properly. However, at Perry, engine disassembly and inspection was performed before NRC-required preoperational tests were performed. Thus, the preoperational testing at Perry will be the vehicle by which the integrity of the reassembled engine is verified. By letter dated March 25, 1985 (B. J. Youngblood to M. R. Edelman), the staff permitted preoperational tests to exceed 185 psig BMEP, subject to certain conditions.

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It is the staff's position that the preoperational tests conform with current NRC requirements given in RGs 1.108 and 1.9 and that preoperational testing includes but does not duplicate the post-reassembly testing recommended by PNL, stated above, and as modified in the March 25, 1985 letter regarding load. Accordingly, the staff approved the applicant's request to eliminate the 20 additional fast starts previously proposed in a letter dated May 13, 1985 (B. J. Youngblood to M. R. Edelman).

It is the staff's understanding that the applicant will also be performing the TDI Owners Group-recommended partial teardown and selected inspection at the completion of the planned RG 1.108 preoperational tests (approximately 100 hours of engine operation). The staff considers this partial teardown to be sufficiently "major" to require the applicant to perform additional test runs of the Perry diesel engine after completion of these inspections. To satisfy this requirement, it would be sufficient to perform the engine break-in tests recommended by TDI, after a "major" engine inspection/maintenance outage. The applicant's intention to perform such test runs was committed to in a letter dated February 8, 1985 (M. R. Edelman to B. J. Youngblood). The staff's understanding of the definitive test steps was documented in a letter to the applicant dated July 22, 1985 (B. J. Youngblood to M. R. Edelman).

8.4 Other Electrical Features and Requirements for Safety

8.4.4 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

During a visit to the plant site in September 1983, the staff found that electrical equipment and cabling audited were installed in conformance with design criteria except for two items. One item concerned the diesel generator design feature to override the "test mode" to permit response to LOCA signals. The second item was that the dc power supply monitoring system did not provide an indicator and alarm to signal a battery fuse-open or circuit breaker-open occurrence in the control room. These items were considered significant enough to reopen SER Confirmatory Issue (35) in SSER No. 4, and to impose License Condition (22) requiring installation of these design features before Perry Unit 1 fuel load.

By letter dated May 9 and May 29, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided design information correcting these open items. The staff's evaluation of the design information follows:

(1) Diesel Test Override

Regulatory Guide 1.9 requires that a diesel generator have a design feature that an emergency start signal to the diesel generator shall override all other operating modes and return control of the diesel generator unit to the automatic control system. The staff developed the position that, upon receipt of a LOCA signal when in the test mode, the diesel generator should trip. In the FSAR, the applicant committed to comply with the above position. During the site visit, the staff reviewed the elementary diagram of the diesel generator breakers and found that the diesel generator did not have this design feature. To comply with the staff position, the applicant submitted a modified design shown on the elementary diagrams B-208-206-SH24 Rev. H, B-2080206-SH30 Rev. G, and B-208-206-SH37 Rev. J,

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transmitted by letter dated May 9, 1985. Therefore, Division 1, 2, and 3 diesel generator control circuits will automatically change from the test mode if a safety injection signal occurs during the test. The modified design feature on the Perry diesel generator complies with the staff's position and, therefore, this item is acceptably resolved.

(2) DC Undervoltage Alarm

The specific requirements for the dc power supply monitoring system derive from recommendations embodied in IEEE Std. 308-1974 and guidelines in Regulatory Guide 1.47. On the basis of the above documents, specific guidelines were used in the licensing review of the dc power system designs. In the Perry design, the battery breaker or fuse open alarm has not been provided. During the site visit, the applicant committed to install an undervoltage relay on the battery side to provide alarm for a fuse-open condition. The design change to install undervoltage relay on the battery side is reflected on drawing D-206-051/N. The undervoltage relay is set at 125 volts and as soon as the fuse or breaker of the battery opens, the voltage of the battery decreases from the charging voltage, about 135 volts, to the battery's open voltage, 123 volts. The undervoltage relay drops out at 125 volts and sends an alarm to the main control room. The Perry design for the indication and alarm of the battery breaker open thus satisfies the staff's position and, therefore, this item is acceptably resolved.

On the basis of the above, SER Confirmatory Issue (35) is again considered to be resolved. In addition, License Condition (22) is being deleted since the applicant has committed in the FSAR to install the above related design features before Perry Unit 1 fuel load.

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9 AUXILIARY SYSTEMS

9.3 Process Auxiliaries

9.3.1 Compressed Air Systems

In Section 9.3.1 of the SER, the staff's evaluation for the compressed air systems, which included a safety-related instrument air system, was based on the applicant's full compliance with ANSI Standard MC-11-1 (ISA-S7.3), with air quality of 3 microns or less in particulate size. Subsequently the applicant, in FSAR Amendments 17 and 18, proposed an air quality of 40 microns or less in particulate size.

When questioned by the staff regarding this change, the applicant, in a submittal dated August 8, 1985 (M. R. Edelman to B. J. Youngblood), committed to (1) meet the design guidelines of ANSI Standard MC-11-1 (ISA-S7.3) with the exception that the air quality would have a particulate size of 40 microns or less instead of 3 microns; (2) test instrument air quality for degradation, on annual basis, downstream of the purification equipment; and (3) perform maintenance, as required, to detect and correct the degradation of air quality per Perry procedures for the safety-related instrument air system. The applicant further stated that the instrument air systems will retain the 3-micron filters downstream of the compressor and receiver tank, which are monitored for clogging, inspected semiannually, and replaced, as necessary, to establish air quality having 40 microns or less particulate size limit. The staff has reviewed the safety-related equipment list, utilizing instrument air, with vendor-recommended air quality and concluded that the available instrument air quality exceeds the required air quality for the involved equipment and, thus, instrument air quality is acceptable. On the basis of this review, the staff concludes that the instrument air quality is acceptable for the intended functions of the safety-related equipment with the exception to the ANSI Standard requested.

9.3.2 Process Sampling System

In Section 9.3.2 of SSER No. 4, the staff concluded that the applicant's proposed postaccident sampling system met all of the 11 criteria of TMI Action Plan Item II.B.3 (NUREG-0737) and was, therefore, acceptable. By letter dated September 6, 1985 (M. R. Edelman to B. J. Youngblood), the applicant proposed to modify the boron analysis and provided additional information for clarification of the in-line analyzers for containment atmospheric hydrogen. The applicant proposes to modify the portable Dionex 2010i ion chromatography system to permit boron determination at the chemical analysis panel. This modification should result in an improvement in accuracy of ±5%. The applicant also proposes to use the combustible gas control system, which contains two redundant in-line hydrogen analyzers (Class 1E), to measure hydrogen concentration in the containment atmosphere.

The accuracy, range, and sensitivity of the boron analysis are consistent with the recommendations of Regulatory Guide 1.97, Rev. 3, and the clarifications of NUREG-0737, Item II.B.3, and, therefore, the analysis is acceptable.

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Criterion (8) of Item II.B.3 of NUREG-0737 requires backup sampling through grab samples for in-line monitoring. Since containment hydrogen levels will be obtained by redundant safety-related systems required by Item II.F.1.6 of NUREG-0737, it is acceptable not to have grab sampling capability. The staff has determined that these provisions meet Criteria (2), (7), (8), and (10) of TMI Action Plan Item II.B.3 and are, therefore, acceptable.

On the basis of the above evaluation, the staff concludes that the proposed modifications of the boron analysis and the in-line hydrogen analyzers meet the criteria of TMI Action Plan Item II.B.3 and are, therefore, acceptable.

9.5 Fire Protection Systems

9.5.1 Introduction

In SSER No. 4, it was reported that the staff's review of Perry fire protection program was complete. However, during the staff's site audit in March 1985, concerns were expressed pertaining to the applicant's commitments, justifications for certain fire protection designs, and the degree of compliance with the required staff guidelines. By letter dated April 16, 1985 (B. J. Youngblood to M. R. Edelman), the applicant was informed of these concerns. By letters dated February 11, May 3, May 15, May 21, June 26, August 1, August 30, September 12, September 26, and October 3, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided additional information; by letter dated May 23, 1985 (M. R. Edelman to B. J. Youngblood), the applicant submitted Revision 4 to the Fire Protection Evaluation Report (FPER); and by letters dated June 12 and September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested additional deviations from the staff's guidelines.

Revision 4 to the FPER and the CEI letters dated June 12 and September 12, 1985 contain changes which are the result of continued program development and the applicant's reexamination of its Appendix R safe shutdown analysis. Only those changes that affect the staff's previously reported safety evaluations are addressed in this supplement.

9.5.1.3 Fire Brigade and Fire Brigade Training

Section 13.1.2.5 of this supplement discusses the staff's acceptable findings with respect to the applicant's current plans for fire brigade staffing and training. The current plans do not alter the staff's findings documented in Section 9.5.1.3 of the SER.

9.5.1.4 General Plant Guidelines

9.5.1.4.1 Building Design

In Revision 3 of the FPER, the applicant stated that all penetrations to fire areas are sealed to maintain the 3-hour fire resistance rating of the barriers with penetration seal designs tested in accordance with ASTM Standard E-119 and that cable penetrations in fire barriers are sealed consistent with the fire resistance ratings of the barriers. This is consistent with Section C.5.a.(3) of Branch Technical Position (BTP) CMEB 9.5-1.

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During the site audit, the staff observed that conduits 4 inches or less in diameter were not sealed in accordance with the applicant's commitment.

By letter dated May 3, 1985 (M. R. Edelman to B. J. Youngblood), the applicant proposed sealing criteria for conduit 4 inches or less in diameter that do not meet the guidelines without justification. By letter dated June 10, 1985 (B. J. Youngblood to M. R. Edelman), the applicant was informed that the proposed sealing criteria were not acceptable.

By letters dated June 26 and August 1, 1985 (M. R. Edelman to B. J. Youngblood), the applicant submitted revised sealing criteria and provided the results of fire tests on conduits sealed in accordance with the proposed criteria that were exposed to the ASTM E-119 standard time-temperature curve.

The proposed sealing criteria, which apply only to conduits 4 inches or less in diameter, are delineated in Exhibit 1 to the applicant's August 1, 1985 letter and will be included in a future FPER revision (Rev. 5 still to be submitted by CEI). The proposed sealing criteria permit unsealed conduits where automatic areawide fire suppression systems are provided on both sides of the fire barrier and where there is no threat to redundant safe shutdown components. Where a potential exposure to redundant safe shutdown trains exists, conduits will be sealed at the barrier or the first opening on one or both sides of the barrier depending on the diameter and length of the conduit.

The fire test demonstrated that the conduits sealed and/or configured in accordance with the applicant's proposal prevent smoke and hot gas propagation through the conduits throughout the 3-hour test period. None of the unexposed side thermocouples exceeded the acceptance criteria temperature specified by either ASTM*, ANI*, or IEEE* for the 3-hour fire rating of the barrier.

On the basis of its evaluation of the design information and test results provided, the staff concludes that the applicant's sealing criteria for conduits 4 inches or less in diameter will provide an equivalent level of protection to that achieved by compliance with Section C.5.a(3) of BTP CMEB 9.5-1. The applicant's conduit sealing proposal is, therefore, an acceptable deviation from Section C.5.a(3) of BTP CMEB 9.5-1.

In the SER, the staff reported that all door assemblies installed in fire rated barriers have fire resistance ratings commensurate with the ratings of the barriers in which they are installed and are Underwriters Laboratories, Inc. (UL) labeled. During the site audit, the staff observed numerous door assemblies that were not UL labeled. The applicant agreed to have each door assembly UL labeled or tested. By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that all fire door assemblies in fire barriers have been labeled by Underwriters Laboratories. The staff concludes that fire doors are now provided in accordance with Section C.5.a of BTP CMEB 9.5-1 and are, therefore, acceptable.

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*ASTM--American Society for Testing and Materials
ANI--American Nuclear Insurers
IEEE--Institute of Electrical and Electronic Engineers

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During the site audit, the staff tested four fire dampers. Two of the four dampers failed to close. By letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that the damper failures were caused by improper alignment of the damper blades and the presence of debris in the damper sections. To ensure proper damper functioning, the applicant committed to revise its testing procedures and surveillance operations to include removing dirt and debris, checking movement of latches, and checking stacking of the blade pack. The staff finds this acceptable.

In the letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant also informed the staff that all dampers had been reevaluated against new manufacturer's criteria, and committed to have all required modifications for dampers completed before Perry Unit 1 fuel load; to have all dampers retested; and to have all tests witnessed by quality assurance inspectors under the Quality Assurance Program. The staff finds that performance of these activities will verify that all fire dampers have been installed and tested in accordance with the manufacturer's recommendations. Therefore, on the basis of the applicant's commitments, the staff concludes that these fire damper issues are resolved.

By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that the chart storage room at elevation 659 ft 0 in. of the control complex (fire area 1CC-5b) will be converted to a lunchroom. Table 9.2 in SSER No. 4 is hereby revised to indicate that this area will have a fuel load of 10,000 Btu/ft^2, a fire severity of 13 minutes, and that automatic suppression will not be provided. These changes do not affect the staff's previous safety evaluation concerning the gypsum board walls in this area.

During the site audit, the staff observed gypsum board walls serving as fire barriers in the cable spreading area that were not installed in accordance with the wall design approved in SSER No. 4. By letter dated May 15, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that these walls were restored to the approved configuration. The staff finds this acceptable.

In Table 9.2 of SSER No. 4, the staff listed the plant areas using a specific gypsum wall design acceptable, based on the staff's fire hazards analyses. The pertinent parameters of the staff analyses were also listed in Table 9.2. Subsequently, the staff identified these walls in several plant areas and zones that were not listed in Table 9.2 of SSER No. 4. These additional locations are listed in Table 9.3, being added to the SER by this supplement. On the basis of its safety evaluation contained in SSER No. 4, the staff concludes that the use of these walls in these additional areas and zones is acceptable.

By letters dated May 15 and August 30, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that horizontal gypsum plank and wallboard assemblies and gypsum-wallboard multi-purpose walls and ceilings are being used as fire barriers in the control complex. The horizontal barriers serve as fire barriers between the cable chases and the elevation 693 ft 2 in. ventilation duct chase and between the computer rooms and cable spreading rooms. Barrier construction consists of two 1-in.-thick layers of gypsum plank attached by screws to the top sides of steel joists. Gypsum wallboard is fastened to the underside of the steel joists to form a ceiling. The cable chase ceilings

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consist of two layers of ½-in.-thick gypsum wallboard. The computer room ceilings consist of one layer of ½-in.-thick gypsum wallboard and one layer of acoustical tile. These barriers have not been tested to establish their fire resistance ratings.

The staff has reviewed the Underwriters Laboratories Fire Resistance Directory, the Gypsum Association Fire Resistance Design Manual, and the National Fire Protection Association Handbook, and finds that the applicant's designs are similar to those that have been tested and listed or that have been estimated to have fire resistance ratings of from 1 to 2 hours.

Table 9.4 (added to the SER by this supplement), developed from the applicant's submittals, lists each control complex fire area where gypsum plank and wallboard barriers are installed, the fuel load and estimated fire severity for each area, and whether or not the area has a fire suppression system. All of the areas have a fire detection system. The fire load on each side of the gypsum board walls is either less than 1 hour, or, if the fire load is higher than 1 hour, additional protection is provided by a suppression system.

On the basis of its evaluation of this information, the staff concludes that the gypsum plank and wallboard barriers are adequate for the fire areas listed in Table 9.4 and are, therefore, acceptable.

The multi-purpose walls consist of steel plate welded to studs with three layers of gypsum wallboard on each side. The wallboard is attached with drywall adhesive. By letters dated August 30 and September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that a fire test conducted by Underwriters Laboratories in accordance with the requirements of ASTM E-119 demonstrated that this multi-purpose wall design will perform as a satisfactory fire barrier for a minimum of 1 hour and 45 minutes under test conditions.

Table 9.5 (added to the SER by this supplement), developed using the applicant's submittals, lists the fire areas and zones in the control complex where gypsum wallboard multi-purpose walls and/or ceilings are installed; the fuel load and estimated fire severity for each location; and whether or not there is a fire suppression system. All of the locations have a fire detection system. The fire load on each side of each wall yields an equivalent fire severity of less than 1 hour and 45 minutes in all cases. Moreover, where the equivalent fire severity exceeds 45 minutes, additional protection is provided by an automatic suppression system.

On the basis of its evaluation of this information, the staff concludes that the multi-purpose gypsum wallboard walls and ceilings are adequate fire barriers for the fire areas and zones listed in Table 9.5, and are, therefore, acceptable.

The SER stated that the water spray systems protecting the oil-filled transformers can be manually controlled by the operator from the control room. In fact, the water spray systems can be manually actuated at the deluge system riser, but not from the control room. This meets Section C.5.a(13) of BTP CMEB 9.5-1 and is, therefore, acceptable.

In the SER, the staff reported that the exterior walls of all buildings containing safety-related equipment located within 50 feet of oil-filled transformers

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have a minimum fire resistance rating of 3 hours. By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant advised the staff that the main transformers for Unit 1 are located within 20 feet of a 2-hour fire rated turbine building wall. The turbine building contains safety-related instruments and circuits associated with the turbine stop valves. These components are separated by at least 200 feet from the wall common with the transformers. Automatic sprinkler protection is provided in the elevation containing these components.

For a transformer fire to damage these safety-related components, it would have to burn through the 2-hour fire rated exterior turbine building wall and then spread 200 feet through an area of the turbine building that has sprinklers. In the event of a fire involving a transformer, the transformer water spray system would control the fire until the fire brigade arrives. It is the staff's opinion that the fire brigade could extinguish the fire well before the 2-hour fire rated exterior wall is breached. In the unlikely event that the fire could not be promptly extinguished, the fire brigade could protect the exposed wall and effectively prevent the fire from spreading into the turbine building. Therefore, reasonable assurance exists that a Unit 1 main transformer fire will not damage the safety-related components located in the turbine building.

On the basis of its evaluation findings above, the staff concludes that the Perry Unit 1 main transformers do not present a fire exposure threat to the safety-related components located in the turbine building. The 2-hour fire rated turbine building wall separating these transformers from the safety-related components is, therefore, an acceptable deviation from Section C.5.a(13) of BTP CMEB 9.5-1.

9.5.1.4.2 Safe Shutdown Capability

(2) Alternate Shutdown Capability

In SSER No. 3, the staff reported that dry chemical portable extinguishers and hose stations are available in the area housing remote shutdown panels. In fact, halon portable extinguishers are available within the area and water hose stations are available in adjacent areas. This meets Section C.5.c of BTP CMEB 9.5-1 and is, therefore, acceptable.

(3) Deviations From the Guidelines of BTP CMEB 9.5-1

By letter dated June 16, 1982 (D. R. Davidson to A. Schwencer), the applicant requested deviations from Section C.5.b of BTP CMEB 9.5-1 to the extent that it requires the protection of redundant safe shutdown components by an areawide fire suppression system. In SSER No. 3, the staff approved deviations from providing automatic fire suppression systems in the following fire areas and zones:

- control complex emergency closed cooling pump area, elevation 574 ft 10 in. (fire zones CC-1b and CC-1c)
- Unit 1 control complex elevator and stairway vestibule, elevation 620 ft 6 in. (fire zone 1CC-3e)
- Unit 1 control complex HVAC equipment room, elevation 679 ft 6 in. (fire zone 1CC-6)

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- diesel generator building corridor, elevation 620 ft 6 in. (fire zone DG-1d)

- emergency service water pumphouse (fire area ESW-1a)

- intermediate building, elevation 620 ft 6 in. (fire zone IB-3)

By letters dated June 12 and September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested eight additional deviations to the extent that the requirements of Section C.5.b of BTP CMEB 9.5-1 are not met because redundant safe shutdown components (1) are not separated by 3-hour fire rated barriers, (2) are not separated by more than 20 feet free of intervening combustibles with areawide fixed automatic suppression, or (3) are not enclosed in 1-hour fire rated barriers with areawide fixed automatic suppression.

Areas Without 3-Hour Fire Rated Barriers

The applicant has requested a deviation from Section C.5.b(2)(a) of BTP CMEB 9.5-1 for the reactor building (fire zones 1RB-1a, 1RB-1b, 1RB-1c, and 1RB-1d) to the extent that redundant safe shutdown components are not separated by 3-hour fire rated barriers.

The reactor building is one fire area. Radiation barriers divide the reactor building into four concentric zones. Zone 1RB-1a extends inward from the reactor building wall to the containment vessel wall, zone 1RB-1b extends from the containment wall to the drywell wall, zone 1RB-1c extends from the drywell wall to the reactor vessel, and zone 1RB-1d is the region directly below the reactor vessel and inside the vessel pedestal. The containment is not inerted. Fire zones 1RB-1a, 1RB-1b, and 1RB-1c contain redundant divisions of safe shutdown divisions. The barriers separating the zones are not 3-hour fire rated.

The staff finds that the zone boundaries between the redundant safe shutdown divisions defined by the applicant, i.e., the containment vessel wall, the drywell wall, and the reactor vessel pedestal, will all serve as noncombustible radiant energy shields between the redundant trains. This configuration satisfies Section III.G.2.f of Appendix R to 10 CFR 50 requirements as a means of fire protection inside noninerted containments. Therefore, the lack of 3-hour fire rated barriers is not a deviation from the staff's guidelines.

Areas Without 20 Feet Free of Intervening Combustibles

The applicant has requested a deviation from Section C.5.b of BTP CMEB 9.5-1 for control complex elevation 599 ft 0 in. (fire area CC-2), to the extent that it requires the separation of redundant safe shutdown components by a horizontal distance of more than 20 feet with no intervening combustibles.

Fire area CC-2 is the entire second floor of the control complex and contains both method A and method B cables. The fuel load in the area yields an equivalent fire severity of approximately 100 minutes. The area is protected by an areawide ionization detection system and, with the exception of the hallway, an automatic sprinkler system. Where the cables for both trains are within 20 feet of each other, at least one train is wrapped with a 1-hour fire rated barrier. In the northwest quadrant of the fire area, these redundant raceways are not separated by 20 feet free of intervening combustibles.

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Because this area is protected by an areawide fire detection system, the staff has reasonable assurance that any fire would be detected in its early stages and would be extinguished by the plant fire brigade. If the fire spreads rapidly before the fire brigade arrives, the automatic sprinklers would operate and control the fire. The fire rated barriers will provide passive protection until the fire brigade arrives or the sprinkler system operates. Therefore, there is reasonable assurance that one safe shutdown train will be available following a fire in this area.

The staff concludes that the presence of intervening combustibles between redundant trains in fire area CC-2 does not significantly reduce the level of fire safety. This is, therefore, an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Areas Without Automatic Suppression Systems

The applicant has requested deviations from providing automatic suppression systems in the Unit 2 control complex HVAC equipment room, elevation 679 ft 6 in. (fire zone 2CC-6), the auxiliary building corridor, elevation 574 ft 10 in. (fire area 1AB-1g), and the auxiliary building fire area composed of fire zones 1AB-1b and 1AB-3a.

The design of and the fire hazards analysis for the Unit 2 control complex HVAC equipment room (fire area 2CC-6) is essentially identical to the Unit 1 control complex HVAC equipment room (fire area 1CC-6). The staff previously found the lack of automatic suppression to be an acceptable deviation for fire zone 1CC-6. Therefore, the staff finds the lack of automatic suppression in fire zone 2CC-6 to be an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Fire area 1AB-1g is the common corridor for the 574 ft 10 in. elevation of the auxiliary building. This area contains redundant safe shutdown components. Only the method B residual heat removal panel, which contains instrumentation that could affect operation of method A systems, has less than 20 feet of separation distance between redundant components. Automatic fire detection is provided throughout the area. The applicant proposes to enclose one train of instruments and their cables in a 1-hour fire rated barrier and to erect a heat shield adjacent to the RCIC panel. The low fuel load in this zone yields an equivalent fire severity of less than 10 minutes.

Auxiliary building fire zones 1AB-1b and 1AB-3a form one fire area. The connections between these two zones are unsealed pressure relief openings and undampered HVAC duct penetrations in a common wall. Zone 1AB-1b has method A and method B safe shutdown components. Zone 1AB-3a has method B components. There is more than 20 feet of separation free of intervening combustibles between the method B safe shutdown components within fire zone 1AB-3a and the method A safe shutdown components in fire zone 1AB-1b. The combustible loading in fire zone 1AB-1b yields an equivalent fire severity of less than 15 minutes. The combustible loading in fire zone 1AB-3a yields an equivalent fire severity of less than 5 minutes.

Automatic fire detectors are installed throughout the fire area and in the HVAC supply and exhaust ducts. The applicant proposes to enclose one train of cables in zone 1AB-1b needed for safe shutdown in 1-hour fire rated barriers.

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Because the in situ fuel loads are low, redundant systems have either adequate separation or have been enclosed in fire rated barriers, and early warning fire detection is provided in each of the above areas, the staff has reasonable assurance that one train of safe shutdown systems will be free of damage following a fire.

On the basis of the above findings, the staff concludes that the installation of an automatic fire suppression system in the auxiliary building common corridor at elevation 574 ft 10 in. (fire area 1AB-1g) and the auxiliary building fire area composed of fire zones 1AB-1b and 1AB-3a would not significantly increase the level of fire safety. The lack of an automatic fire suppression system in fire area 1AB-1g and fire zones 1AB-1b and 1AB-3a is, therefore, an acceptable deviation from Section C.5.b(2) of BTP CMEB 9.5-1.

Areas With Partial Coverage Automatic Suppression Systems

The applicant has requested deviations from providing an areawide automatic fire suppression system in the following fire areas and zones.

- control complex emergency closed cooling pump area, elevation 574 ft 10 in. (fire area CC-1)
- auxiliary building (fire area composed of fire zones 1AB-1e and 1AB-3b)
- auxiliary building (fire area composed of fire zones 1AB-1c and 1AB-2)
- intermediate building (fire zones IB-2, IB-3, and IB-4)

Fire area CC-1 is the emergency closed cooling pump area located on the 574 ft 10 in. elevation of the control complex. It contains redundant safe shutdown components and cables. Cables of one redundant safe shutdown division are enclosed in a 1-hour fire rated barrier where the redundant trains are separated by less than 20 feet. The intervening area between the cables is free of combustibles.

Some redundant components are separated by a cumulative horizontal distance in excess of 20 feet by a gypsum wallboard barrier that extends from floor to ceiling, but not from wall to wall. This barrier is constructed in accordance with the design the staff approved in Section 9.5.1.4(a) of SSER No. 4. There are redundant instrument racks and redundant valves separated by less than 20 feet. There are no in situ combustibles around these redundant components. The combustible loading in the area yields an equivalent fire severity of less than 30 minutes. Ionization detectors are installed throughout the area. Automatic sprinklers are installed over all safe shutdown systems and cover approximately 45% of the fire area. In addition to the ceiling level sprinklers, fast-response-type sprinklers have been installed directly above and between those redundant components separated by less than 20 feet.

If a fire were to occur where there are no sprinklers, it would be detected by the existing fire detection system before the fire spread significantly. It would then be suppressed by the plant fire brigade before it could damage shutdown systems. If the fire spread rapidly before the brigade arrived, individual sprinklers in the protected portion of the area would operate to both limit the

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spread of fire and to protect the shutdown-related systems until the fire was controlled. Moreover, the cable protection and gypsum board barrier will provide passive protection until the fire brigade arrives or the sprinkler system operates. In either event, the staff has reasonable assurance that a safe shutdown capability would remain free of damage.

On the basis of its evaluation, the staff concludes that the installation of additional automatic suppression or additional fire barriers between redundant safe shutdown components in control complex fire area CC-1 would not significantly increase the level of fire safety. The staff finds acceptable deviations from Section C.5.b of BTP CMEB 9.5-1 involving the lack of an areawide fire suppression system and the lack of 20 feet of separation between redundant components. The existing fire protection provided for fire area CC-1 is, therefore, acceptable.

During the site audit, the staff noted cable tray concentrations with greater than six cable trays without automatic sprinkler protection in fire zone 1AB-3b (auxiliary building, elevation 620 ft 6 in.). By letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant committed to install automatic sprinkler protection over the concentrated cable trays in this fire zone. By letter dated June 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant identified this partial protection as a deviation from staff guidelines and requested staff approval.

Auxiliary building fire zones 1AB-1e and 1AB-3b form one fire area. The connections between these two zones are unsealed pressure openings and undampered HVAC duct penetrations in a common wall. Zone 1AB-1e had method B safe shutdown components. Zone 1AB-3b contains method A and method B circuits. The combustibles loading in fire zone 1AB-1e yields an equivalent fire severity of approximately 30 minutes. The combustible loading in fire zone 1AB-3b yields an equivalent fire severity of approximately 37 minutes.

Automatic fire detectors are provided throughout the fire area and in the HVAC system supply and exhaust ducts. The applicant proposes to provide partial automatic sprinkler coverage in fire zone 1AB-3b and to enclose one train of cables needed for safe shutdown in both zones in 1-hour fire rated barriers.

Auxiliary building fire zones 1AB-1c and 1AB-2 form one fire area. Unprotected grating for pressure relief and undampered HVAC system ducts in the floor/ceiling connect the zones. Zone 1AB-1c contains method A safe shutdown components. Zone 1AB-2 contains methods A and B safe shutdown components. The combustible loading in zone 1AB-2 yields an equivalent fire severity of approximately 30 minutes. The combustible loading in zone 1AB-1c yields an equivalent fire severity of less than 10 minutes.

Automatic fire detectors are provided throughout zones 1AB-1c and 1AB-2 and automatic sprinklers are installed throughout zone 1AB-1c. The applicant proposes to enclose one train of safe shutdown circuits in zone 1AB-2 in 1-hour fire rated barriers.

If a fire were to occur in a place where there are no sprinklers, it would be detected by an existing areawide fire detection system before the fire spread significantly. It would then be suppressed by the plant fire brigade before

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shutdown systems were damaged. If the fire spread rapidly before the brigade arrived, sprinklers in the protected portion of the area would operate to limit the fire's spread and to protect the shutdown-related systems until the fire was controlled. The cable protection will also provide passive protection until the fire is extinguished. In either event, the staff has reasonable assurance that a safe shutdown capability would remain free of damage.

On the basis of the above findings, the staff concludes that installing areawide automatic suppression capability in these fire areas would not significantly increase the level of fire safety. Therefore, the staff finds the installation of partial automatic suppression systems in the auxiliary building fire area composed of fire zones 1AB-1e and 1AB-3b and the auxiliary building fire area composed of fire zones 1AB-1c and 1AB-2 to be acceptable deviations from Section C.5.b(2) of BTP CMEB 9.5-1. The existing and proposed fire protection is, therefore, acceptable.

By letter dated June 16, 1982 (D. R. Davidson to A. Schwencer), the applicant requested a deviation from installing an automatic suppression system at elevation 620 ft 6 in. of the intermediate building (fire zone IB-3). In SSER No. 3, the staff approved the deviation. By letter dated June 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant revised the original deviation request. The applicant now requests a deviation from providing an automatic fire suppression system throughout the building as opposed to at one elevation of the building.

The intermediate building is a single fire area. Each floor is a separate fire zone. With the exception of a 3-inch rattle space, each floor is separated from the others by 3-hour fire rated barriers. The rattle space is covered by a ¼-inch-thick steel cover.

Elevations 574 ft 10 in. (fire zone IB-1) and 682 ft 6 in. (fire zone IB-5) do not contain any safe shutdown components. Elevations 599 ft 0 in. (fire zone IB-2) and 620 ft 6 in. (fire zone IB-3) both contain redundant safe shutdown components. Elevations 654 ft 6 in. and 665 ft 0 in. (fire zone IB-4) contain only one division of safe shutdown components.

With the exceptions of fire zone IB-2, which has a combustible load yielding an equivalent fire severity of 38 minutes, and fire zone IB-3, which has a combustible load yielding an equivalent fire severity of 50 minutes, the maximum fire severity in the intermediate building is 10 minutes. There are no combustible materials located around the rattle space. Cables are located at least 15 feet from the rattle space.

Fire detection has been provided throughout fire zones IB-2, IB-3, and IB-4 and partial fire detection has been provided in fire zones IB-1 and IB-5. An automatic sprinkler system is installed throughout fire zone IB-2. The applicant proposes to install automatic sprinklers over all safety-related cables in fire zone IB-3, which accounts for the 50-minute equivalent fire severity in this zone, and to enclose one train of safe shutdown cables in 1-hour fire rated barriers throughout fire zone IB-3.

The in situ fuel loads are low on the two elevations that do not contain safe shutdown components (fire zones IB-1 and IB-5); therefore, the staff does not expect a fire of significant magnitude or duration to occur at these elevations.

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If a fire should occur, it would be detected by existing automatic fire detection in these locations or in adjoining zones. The fire would be suppressed by the fire brigade using manual fire fighting equipment. Because these locations do not contain safe shutdown systems, fire damage in them will have no affect on safe shutdown.

If a fire were to occur at any other elevation in a location that has no sprinklers, it would be detected by the existing fire detection system before the fire spread significantly, and would be suppressed by the plant fire brigade before shutdown systems were damaged. If the fire spread rapidly before the fire brigade arrived, individual sprinklers in the protected portions of the area would operate to limit the fire's spread and to protect the shutdown-related systems until the fire was controlled.

The staff was concerned that because the rattle spaces are not sealed with a fire rated material, fire would propagate through the gap, damaging redundant shutdown divisions. However, because the rattle space is covered by a steel cover, the staff does not expect damaging amounts of smoke and hot gases to propagate to the adjoining area before the fire brigade arrives. The staff finds that there is reasonable assurance that one train of safe shutdown systems will be free of damage following a fire in the intermediate building.

On the basis of the above, the staff concludes that the installation of an automatic fire suppression system throughout the intermediate building would not significantly increase the level of fire safety. The lack of automatic fire suppression systems in fire zones IB-1, IB-4, IB-5, and part of IB-3, is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1. The fire protection provided and proposed for the intermediate building is, therefore, acceptable.

9.5.1.4.4 Control of Combustibles

In the SER, the staff reported that hydrogen piping is not routed through areas containing safety-related equipment. By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that hydrogen piping associated with the turbine generator hydrogen seal oil system is routed through the turbine building which contains safety-related instrumentation and circuits. The hydrogen piping is separated from these components by at least 150 feet. The area between the hydrogen piping and the safety-related components is protected by an automatic sprinkler system. Loss of these safety-related components will not affect safe plant shutdown.

Because of the spatial separation between the safety-related components and the intervening sprinkler protection, the staff finds that the hydrogen piping does not present a significant fire exposure to the safety-related components installed in the turbine building. The staff therefore concludes that the presence of the hydrogen piping in the turbine building is an acceptable deviation from Section C.5.d of BTP CMEB 9.5-1.

9.5.1.4.7 Lighting and Communication

In SSER No. 3, the staff reported that the emergency lighting will provide illumination of not less than 1.0 foot-candle measured at the floor. By letter

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dated August 30, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that emergency lighting levels of less than 1.0 foot-candle may be measured at the floor. However, the applicant's human factors engineering walkdown demonstrated that the emergency lighting system will provide adequate illumination to perform required safe shutdown operations and for access and egress routes. The staff finds this acceptable.

By letters dated June 12 and October 3, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested a deviation from Section C.5.g of BTP CMEB 9.5-1 to the extent that it requires emergency lighting units to be equipped with 8-hour battery power packs in the control room.

The control room lighting fixtures are powered from two lighting panels. One of the two lighting panels (R71-P083) is powered from the Division 1 safety-related power system. The second lighting panel (R71-P085) is powered from the auxiliary, non-Class 1E, power system. Upon a loss of offsite power, the second lighting panel (R71-P085) will be transferred to receive power from the Division 2 safety-related power system. Lamps over the primary plant operating area in the control room are separated into two redundant groups. One group is connected to one lighting panel; the remaining group is connected to the other panel. Either lighting group provides sufficient light to perform safe shutdown operations. In addition, there is 2-hour battery-supplied lighting for the control room that also provides enough lighting to safely shut down the plant.

The ac lighting fixtures in the primary plant operating area of the control room can be powered from either of the two lighting panels and supplied from the redundant divisions of Class 1E ac power systems supplied by the diesel generators. Therefore, the ac-powered lighting can be relied on to function after a fire in the control room.

On the basis of the above, the staff concludes that providing emergency lighting units equipped with 8-hour battery packs would not significantly increase the level of safety. The existing control room emergency lighting is, therefore, an acceptable deviation from Section C.5.g of BTP CMEB 9.5-1.

9.5.1.5 Fire Detection and Suppression

9.5.1.5.1 Fire Detection Systems

In SSER No. 4, the staff reported that the fire detection system conforms to the guidelines of Section C.6.a of BTP CMEB 9.5-1. During the site audit, information was not available to the staff to verify that the detection system was labeled in accordance with NFPA 72D as required by staff guidelines. By letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant confirmed that the plant fire alarm system is Factory Mutual approved and that the system components are listed in the 1984 edition of the Factory Mutual Approval Guide. The staff finds this issue resolved.

In a letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that the sprinkler system supervisory signals will not distinctively indicate the particular trouble function (e.g., valve position, panel trouble, etc.) that is abnormal in the control room in accordance with Section 3-6.2.2 of NFPA 72D. However, the supervisory signal will provide a

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system trouble alarm in the control room and a distinctive function alarm at the local control panel. Therefore, operator response to the local control panel following receipt of a trouble alarm in the control room will enable the specific trouble condition to be determined and cleared. The staff finds this to be an acceptable deviation from Section C.6.c of BTP CMEB 9.5-1.

By letter dated May 6, 1982 (D. R. Davidson to A. Schwencer), the applicant committed to install automatic fire detectors in all areas of the plant containing safety-related equipment. By letter dated March 24, 1983 (M. R. Edelman to B. J. Youngblood), the applicant requested deviations from Section C.6.a(1) of BTP CMEB 9.5-1 to the extent that it requires the installation of fire detectors in all areas that contain or present a fire exposure to safety-related equipment. In SSER No. 4, the staff approved the following deviations from Section C.6.a(1) of BTP CMEB 9.5-1:

- auxiliary building elevation 547 ft 10 in. (fire areas 1AB-1a, 1AB-1d, and 1AB-1f)
- Unit 1 steam tunnel
- Unit 1 turbine building
- Unit 1 heater bay
- auxiliary boiler building

The staff also reported the applicant's commitments to install fire detectors in the intermediate building (fire zones IB-1 and IB-5) and to withdraw the deviation requests for the reactor building (fire zones 1RB-1a and 1RB-1b).

By letter dated June 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested deviations from Section C.6.a(1) of BTP CMEB 9.5-1 to the extent that it requires the installation of fire detectors in the following areas that contain safety-related equipment:

- auxiliary building, elevation 574 ft 10 in. (fire area 1AB-1d)
- intermediate building (fire zones IB-1 and IB-5)
- reactor building (fire zones 1RB-1a and 1RB-1b)
- control complex (fire areas CC-STW and 1CC-638/654)
- radwaste building

By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant withdrew its request for deviation for the control complex elevator vestibule, elevation 638 ft 6 in. (fire area 1CC-638/654).

Auxiliary building fire area 1AB-1d contains process and auxiliary components for the residual heat removal "C" system. Only one division of safe shutdown equipment is located in this fire area. Redundant equipment is located in other areas. The fuel load in this area is low. Ionization detectors are provided in the HVAC exhaust duct.

Because of the low fuel load, the staff does not expect a fire of significant magnitude or duration to occur. If a fire does occur, it will be detected by the exhaust duct detectors and extinguished by the plant fire brigade. Moreover,

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because only one division of safe shutdown equipment is located in this area and because this equipment is separated from redundant equipment by 3-hour fire rated barriers, the staff has reasonable assurance that safe shutdown can be achieved following a fire in this area.

On the basis of the above, the staff finds that the installation of fire detectors in auxiliary building fire area 1AB-1d would not significantly increase the level of fire safety, therefore, the omission of a fire detection systems is an acceptable deviation from Section C.6.a(1) of BTP CMEB 9.5-1.

Intermediate building fire zone IB-1 is at elevations 574 ft 10 in. and 585 ft 0 in. and contains equipment for the liquid radwaste, fuel pool cooling and cleanup, service air, and the reactor building chilled water systems. Intermediate building fire zone IB-5 is at elevation 682 ft 6 in. and contains ventilation equipment for the intermediate and fuel handling buildings. With the exception of the rattle spaces at the reactor building interfaces, both fire zones are separated from other plant areas by 3-hour fire rated barriers. Neither fire zone contains safe shutdown components. The fuel load in both zones is low. Automatic fire detection has been provided over the safety-related components in both zones, but not area wide.

Because the fuel load in each zone is low and because each zone is equipped with a partial fire detection system, the staff does not expect a fire of significant magnitude or duration to occur within either zone. Moreover, because neither zone contains safe shutdown components, the staff is reasonably sure that a fire originating within either zone or affecting either zone through the rattle spaces would not impair safe shutdown capability.

On the basis of the above, the staff concludes that the installation of additional fire detectors in intermediate building fire zone IB-1 or IB-5 will not significantly increase the level of safety. Therefore, the lack of an areawide fire detection system in fire zone IB-1 and fire zone IB-5 is an acceptable deviation from Section C.6.a(1) of BTP CMEB 9.5-1.

The reactor building annulus (fire zone 1RB-1a) is located between the environmental shield wall and the containment vessel wall. The safe shutdown components in this fire zone consist of reactor protection system cables and power and control cables. The cables are enclosed in stainless steel conduits. Redundant divisions are separated by at least 12 feet. The continuously operating ventilation system maintains negative pressure in the annulus relative to the outside. Smoke detectors are located in the ventilation system ducts.

Because of the low fuel load, the staff does not expect a fire of significant magnitude or duration to occur. If a fire does occur, the staff expects it to be detected by smoke detectors in the ventilation system during its early stages and to be extinguished by the plant fire brigade. The spatial separation of the safe shutdown cables as well as their enclosure within stainless steel conduits provide further assurance that at least one train of safe shutdown components will be available following a fire in fire zone 1RB-1a.

On the basis of the above, the staff concludes that the installation of fire detectors in the reactor building annulus would not significantly increase the level of safety. The lack of a fire detection system in fire zone 1RB-1a is, therefore, an acceptable deviation from Section C.6.a(1) of BTP CMEB 9.5-1.

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The reactor building above elevation 689 ft 6 in. (fire zone 1RB-1b) is composed of the region from the containment to the drywell wall. This zone is intended to be used during shutdown as a refueling laydown area. Safety-related systems and components located in this area include containment spray system, containment temperature elements and radiation monitors, combustible gas control systems, containment vessel, and drywell purge ventilation systems. About 30% of the zone consists of an open refueling pool. The fuel load in the zone yields an equivalent fire severity of less than 5 minutes. All areas below elevation 689 ft 6 in. are provided with ionization smoke detectors. The HVAC system draws air above elevation 689 ft 6 in. down through open grating to the lower elevations where these detectors are located. In addition, smoke detectors are installed in the discharge ducts of the HVAC system.

The combustibles in this zone are in limited quantities and widely dispersed. Consequently, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur it would be detected by fire detectors in adjoining locations or in the HVAC system ducts, and, in the staff's opinion, would be extinguished before it could threaten the safe shutdown capability of the plant.

On the basis of the above evaluation, the staff concludes that the installation of a fire detection system in the reactor building above elevation 689 ft 6 in. (fire zone 1RB-1b) would not significantly increase the level of fire safety. Therefore, the omission of a fire detection system is an acceptable deviation from Section C.6.a(1) of BTP CMEB 9.5-1.

The control complex northwest stairwall (fire area CC-STW) is separated from the balance of the plant by 3-hour fire rated barriers. It contains one division of safe shutdown cables in conduits. The combustible loading in the area is negligible.

Because the fuel load is negligible, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur, it would be confined to the area by the perimeter construction. If the division of safe shutdown cables is damaged, safe shutdown can be accomplished using the redundant division located in another fire area.

On the basis of the above, the staff concludes that the installation of fire detectors in the control complex northwest stairwell (fire area CC-STW) will not significantly increase the level of fire safety. Therefore, the lack of fire detectors in fire area CC-STW is an acceptable deviation from Section C.6.a(1) of BTP CMEB 9.5-1.

The radwaste building is a single fire area that houses equipment used for the storage and processing of radioactive waste. It is separated from the balance of the plant by 3-hour fire rated barriers. There is no safe shutdown equipment located in the building. The fuel load in the building is low. The radwaste storage area, which contains the building's highest combustible load, is protected by automatic sprinklers. Ionization detectors are installed in the radwaste control room.

With the exception of the radwaste storage area, the combustible materials are in limited quantities and/or widely dispersed. Consequently, the staff does

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not expect a fire of any significant magnitude or duration to occur. If a fire should occur, it would be detected by fire detectors in adjoining locations or by plant operators who would summon the plant fire brigade. In the event of a fire in the radwaste storage area, the automatic sprinklers would operate and control the fire. Until the fire brigade arrives or the sprinkler system operates, the perimeter construction would limit fire propagation to the area of origin.

Moreover, because the building does not contain any safe shutdown components and is separated from all areas containing safe shutdown components, the staff does not expect a fire in the radwaste building to result in a loss of safe shutdown capability.

On the basis of the above, the staff concludes that the installation of a fire detection system throughout the radwaste building would not significantly increase the level of fire safety. Therefore, the omission of an areawide fire detection system is an acceptable deviation from Section C.6.a(1) of BTP CMEB 9.5-1.

9.5.1.5.2 Fire Protection Water Supply System

In the SER, the staff reported that the fire pump installation was designed in accordance with NFPA 20 and met staff guidelines. By letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that an engine running signal has not been provided in the control room for the diesel engine driver as required by NFPA 20. In the letter, the applicant committed to provide the engine running feature. On the basis of the applicant's commitment, the staff finds that the diesel engine driver fire pump supervision will meet staff guidelines of Section C.6.b(6) of BTP CMEB 9.5-1.

The staff also reported that all water control valves located inside buildings are electrically supervised. By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that three hatch protection sprinkler isolation valves, one station control valve, and one valve on a cross-connection between the cable chase systems will be administratively controlled. This meets Section C.6.c(2) of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.5.3 Sprinkler and Standpipe Systems

In SSER No. 3, the staff reported that all areas of the plant can be reached with an effective hose stream using a maximum of 100 feet of hose. By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that portions of the drywell cannot be reached with 100 feet of hose. Therefore, an additional 100 feet of hose is located at the hose stations located outside of the drywell for use if needed.

The plant water distribution system is capable of supplying these hose stations with an adequate quantity of water and pressure through 200 feet of hose. In addition, sufficient space is available in each of the areas for accessibility and to ensure that the fire hose can be used.

On the basis of the above evaluation, the staff concludes that the use of 200 feet of fire hose in the drywell is an acceptable deviation from Section C.6.c of BTP CMEB 9.5-1.

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9.5.1.5.4 Carbon Dioxide Fire Suppression Systems

In the SER, the staff reported that a carbon dioxide fire suppression system is installed in the chart storage room at elevation 654 ft 0 in. of the control complex (fire zone 1CC-5b). By letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that this fire area will be converted to a lunchroom and that the carbon dioxide system will be removed. Cables of only one safe shutdown train are located in this area and automatic fire detection is provided. This meets Sections C.5.b and C.6.a of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.5.5 Portable Extinguishers

The applicant has committed to provide a complement of fire extinguishers in permanent cabinets at the entrances to containment in accordance with NFPA 10. By letter dated February 11, 1985 (M. R. Edelman to B. J. Youngblood), the applicant indicated that all portable fire extinguishers at the Perry plant have been assigned a unique number and have been listed by location. All portable fire extinguishers will be tested periodically in accordance with their Portable Fire Extinguisher Monthly Inspection periodic test (PTI-P540006). In addition, all portable extinguishers will be inspected yearly according to their Portable Fire Extinguisher Annual Maintenance Inspection periodic test (PTI-OP540007).

The staff finds that these tests are adequate to ensure the availability of portable fire extinguishers to carry into containment during an emergency fire situation. Additionally, the applicant's Fire Protection Instruction FPI-1C addresses where the portable fire extinguishers are located and when they should be used in different plant areas. Furthermore, before doing work of a nature that could result in generating a fire, a fire permit must be obtained in accordance with plant maintenance instructions to ensure the proper precautions are taken, and the proper equipment is maintained close by. Therefore, the staff concludes that no Technical Specification requirement will be necessary to address the use of portable fire extinguishers for containment at Perry.

9.5.1.6 Fire Protection of Specific Plant Areas

9.5.1.6.2 Control Room

In the SER, the staff approved the use of carpeting with an ASTM E-84 flame spread of 25 and a smoke developed rating of 153 in the control room. By letter dated August 30, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided the results of tests conducted on the carpet in accordance with NFPA 253, "Standard Method of Test for Critical-Radiant Flux of Floor Covering Systems," and NFPA 258, "Standard Method of Test for Determining Smoke Generation of Materials," instead of ASTM E-84, and requested staff approval for its use in the control room.

Direct correlation with the ASTM E-84 test results cannot be made. However, the test results indicate that the proposed carpet presents no greater hazard than the previously approved carpet. The average critical radiant flux was determined to be 0.59 watts/cm^2 by NFPA 253 and the average optical density rating was determined to be 432 by NFPA 258. Therefore, the proposed carpet

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is classified by NFPA as a Class I interior floor finish. The staff concludes that the installation of this carpet will not significantly decrease the level of fire safety in the control room and, therefore, is an acceptable deviation from Section C.7.b of BTP CMEB 9.5-1.

In SSER No. 3, the staff reported that the power generation control complex (PGCC), which contained Tefzel-insulated cable and a manually operated carbon dioxide fire suppression system, was acceptable. During the site audit, the staff noticed that not all of the cable installed in the PGCC is Tefzel-insulated. By letter dated April 16, 1985 (B. J. Youngblood to M. R. Edelman), the applicant was advised to justify the use of a manually operated fire suppression system with non-Tefzel-insulated cable or to convert the carbon dioxide system to automatic operation.

By letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that approximately 83% of the PGCC cabling is Tefzel-insulated, and referenced a series of full-scale fire tests of PGCC floor sections conducted by General Electric Co. (GE) (reference Appendix F to NEDO-10466-A and GE letters dated February 28 and May 1, 1985) which showed that for PGCCs with at least 80% Tefzel-insulated cable, introduction of a fire suppressant within 6 minutes of ignition will extinguish the fire before deep-seated burning of the non-Tefzel cable insulation occurs.

In the event of a fire in a floor section, the early warning fire detectors would alert the operators who would extinguish the fire with portable extinguishers or by actuating the carbon dioxide system. The staff concludes that the manually actuated carbon dioxide fire suppression system provides an adequate level of fire protection for the PGCC floor sections and is, therefore, acceptable. This issue is resolved.

In SSER No. 3, the staff reported that ionization detectors have been installed in all cabinets and consoles in the control room. By letters dated September 12 and September 26, 1985 (M. R. Edelman to B. J. Youngblood), the applicant informed the staff that detectors have not been installed in three non-safety-related cabinets. Because areawide ionization detection has been provided, the fuel load is low, and the area is continuously manned, the staff has reasonable assurance that a fire in one of these three cabinets would be promptly detected and extinguished before threatening any other control room cabinets. Therefore, the lack of ionization detectors in the non-safety-related control room cabinets is an acceptable deviation from Section C.7.b of BTP CMEB 9.5-1.

9.5.1.6.4 Switchgear Rooms

In SSER No. 3, the staff concluded that, on the basis of the applicant's commitment to install all switchgear on pedestals, the protection against water damage in the switchgear rooms (fire areas 1CC-3a and 1CC-3c) met staff guidelines of Section C.7.b of BTP CMEB 9.5-1. During the site audit, the staff noted that the 4160-V vital switchgear was installed directly on the floor. By letter dated May 21, 1985 (M. R. Edelman to B. J. Youngblood), the applicant stated that firefighting water can be removed from the switchgear rooms through open doorways in accordance with Chapter 4 of NFPA 92M. By letters dated August 29 and September 12, 1985 (M. R. Edelman to B. J. Youngblood), the applicant provided additional information.

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In the event of a fire in either switchgear room, firefighting water would be directed from the switchgear room into the corridor, down the northwest stairwell of the control complex, and into drains located outside the switchgear rooms. Calculations indicate that even if these drains fail to function, less than 1 inch of water will accumulate. Moreover, no safety-related components susceptible to water damage are located in the anticipated drainage paths. The staff finds that the protection against water damage in the switchgear rooms is in accordance with NFPA 92M and the staff guidelines of Section C.7.e of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.8 Conclusion

On the basis of the above evaluation findings, the staff concludes that the applicant's Fire Protection Program, with the approved deviations, meets the guidelines of BTP CMEB 9.5-1 and GDC 3 and is, therefore, acceptable. The approved deviations are summarized as follows:

(1) sealing inside conduits (SSER 7, Section 9.5.1.4.1)

(2) 2-hour fire rated turbine building wall adjacent to main transformers (SSER 7, Section 9.5.1.4.1)

(3) presence of intervening combustibles between redundant trains in fire area CC-2 (SSER 7, Section 9.5.1.4.2(3))

(4) omission of automatic fire suppression systems in the following plant areas (SSER 3 and SSER 7, Section 9.5.1.4.2(3)):

- Unit 1 control complex elevator and stairway vestibule, elevation 620 ft 6 in. (fire zone 1CC-3e)
- Unit 1 control complex HVAC equipment room, elevation 679 ft 6 in. (fire zone 1CC-6)
- Unit 2 control complex HVAC equipment room, elevation 679 ft 6 in. (fire zone 2CC-6)
- diesel generator building corridor, elevation 620 ft 6 in. (fire zone DG-1d)
- emergency service water pumphouse (fire area ESW-1a)
- auxiliary building corridor, elevation 574 ft 10 in. (fire area 1AB-1g)
- auxiliary building (fire area composed of fire zones 1AB-1b and 1AB-3a)

(5) partial automatic fire suppression systems in the following plant areas (SSER 3 and SSER 7, Section 9.5.1.4.2(3)):

- control complex emergency closed cooling pump area, elevation 574 ft 10 in. (fire area CC-1)

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- auxiliary building (fire area composed of fire zones 1AB-1e and 1AB-3b)
- auxiliary building (fire area composed of fire zones 1AB-1c and 1AB-2)
- intermediate building (fire zones IB-2, IB-3, and IB-4)

(6) hydrogen piping in turbine building (SSER 7, Section 9.5.1.4.4)

(7) emergency lighting without 8-hour battery power packs in the control room (SSER 7, Section 9.5.1.4.7)

(8) automatic sprinkler system alarm supervisory signals (SSER 7, Section 9.5.1.5.1)

(9) lack of areawide fire detection systems in the following areas (SSER 4 and SSER 7, Section 9.5.1.5.1):

- auxiliary building, elevation 574 ft 10 in. (fire area 1AB-1a, 1AB-1d, and 1AB-1f)
- Unit 1 steam tunnel
- Unit 1 turbine building
- auxiliary boiler building
- Unit 1 heater bay
- intermediate building (fire zones IB-1 and IB-5)
- reactor building annulus (fire zone 1RB-1a)
- reactor building, above elevation 689 ft 6 in. (fire zone 1RB-1b)
- control complex northwest stairwell (fire area CC-STW)
- radwaste building

(10) use of 200 feet of fire hose to reach the drywell (SSER 7, Section 9.5.1.5.3)

(11) carpet installed in the control room (SER, SSER 7, Section 9.5.1.6.2)

(12) lack of ionization detectors in non-safety-related control room cabinets (SER, SSER 7, Section 9.5.1.6.2)

9.6 Other Auxiliary Systems

9.6.4 Emergency and HPCS Diesel Engine Cooling Water System

Section 9.6.4 of the SER contains the following license condition with regard to the preheating capability of the high-pressure core spray (HPCS) diesel generator (DG) systems:

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In a letter dated April 29, 1982, the applicant proposed a test program of a minimum of 24 months to demonstrate the HPCS diesel engine's capability to start and accept load within 10 sec during low ambient (40°-65°F) temperatures. The test will be performed during preoperational testing, the monthly surveillance tests, and diesel engine maintenance periods to demonstrate that the HPCS diesel engine does not experience undue wear or degradation of performance when started at the low room temperatures, and that upgrading the preheating capability of the engine to improve first-start reliability is not necessary. At the end of the test period (24 months), the results will be submitted to the staff for review and evaluation. At that time a determination will be made on whether sufficient test data has been presented for the staff to determine that the present design is adequate or that a modification to the diesel engine preheating system is necessary. If insufficient data is available, the applicant has agreed to extend the test program as necessary to obtain an adequate data base. The staff finds the proposed test program acceptable and will make it a condition of the license.

In a letter dated July 9, 1985 (M. R. Edelman to B. J. Youngblood), and in a telephone conversation on July 15, 1985, the applicant provided additional information on the capability of the HPCS diesel generators and requested deletion of License Condition (9) from the Perry SER. The applicant stated that the HPCS diesel engines at Perry are qualified to start within 10 seconds and operate reliably within a room temperature environment down to 40°F. The HPCS diesel generator room will be maintained at a minimum temperature of 40°F, and should the temperature fall below 40°F, the data would alarm in the control room, whereupon the operator would take immediate action to restore room temperature to 40°F. In addition, to further ensure HPCS diesel generator availability, a diesel generator trouble alarm in the control room has local alarm status to warn the operators of improper operation of several diesel engine support functions, including a low engine lube oil temperature condition and keep-warm-system power failure.

The capability of the HPCS diesel generators to start within 10 seconds and operate reliably within room environment temperatures of 40°F and lower has been demonstrated at another nuclear facility which has similar HPCS diesel generators. As such, the staff believes that there is adequate assurance that the HPCS diesel generators at Perry will start and operate reliably under all anticipated conditions. The staff concurs with the applicant's request to delete License Condition (9) from the Perry SER. Consequently, License Condition (9), listed in Section 1.11 of the SER, is hereby deleted.

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Table 9.3 Additional fire areas and zones where gypsum walls are installed

Fire area/zone	Fuel load, Btu/ft²	Fire severity, minutes	Suppression
2CC-6, Division 1 HVAC equipment room	14,000	11	No
CC-6, Units 1 & 2 ventilation duct chase	5,000	4	No
1CC-5c, control room corridor	Negligible	<5	No
CC-2a mechanical equipment room	46,000	35	Yes
CC-2c, Offices	48,000	36	Yes
2CC-4b, Unit 2 Division 2 cable chase	180,000	135	Yes

Table 9.4 Fire areas where horizontal gypsum plank and wallboard barriers are installed

Fire area	Fuel load, Btu/ft²	Fire severity, minutes	Suppression
1CC-4b, Unit 1, Division 2 cable chase	260,000	195	Yes
1CC-4f, Unit 1, Division 1 cable chase	185,000	139	Yes
2CC-4b, Unit 2, Division 2 cable chase	180,000	135	Yes
2CC-4f, Unit 2, Division 1 cable chase	244,000	183	Yes
CC-6, Units 1 & 2 ventilation duct chase	5,000	4	No
1CC-4i, Unit 1 computer room	105,000	79	Partial
2CC-4i, Unit 2 computer room	74,000	56	Partial
1CC-4a, Unit 1, Division 2 cable spreading room	113,000	85	Yes
1CC-4e, Unit 1, Division 1 cable spreading room	124,000	93	Yes
2CC-4a, Unit 2, Division 2 cable spreading room	119,000	90	Yes
2CC-4e, Unit 2, Division 1 cable spreading room	118,000	89	Yes

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Table 9.5 Fire areas and zones where gypsum wallboard multi-purpose walls are installed

Fire area/zone	Fuel load, Btu/ft²	Fire severity, minutes	Suppression
CC-1c, equipment room	7,200	5	Partial
1CC-3a, Division 2 switchgear room	51,000	38	No
1CC-3c, Division 1 switchgear room	51,000	38	No
1CC-4a, Division 2 cable spreading room	113,000	85	Yes
1CC-4e, Division 1 cable spreading room	124,000	93	Yes
1CC-5c, control room corridor	Negligible	<5	No
1CC-6, Division 2 HVAC equipment room	17,000	13	Yes
2CC-6, Division 1 HVAC equipment room	14,000	11	No
1CC-3d, Unit 1 remote shutdown panel room	22,000	17	No
1CC-3e, access corridor	7,800	6	No
1CC-638/654, elevator vestibule	25,000	19	Yes
1CC-5b, lunchroom	10,000	8	No
1CC-6, elevator and stairwell enclosure and ceiling	Negligible	<5	No
2CC-6, stairwell enclosure and ceiling	Negligible	<5	No

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13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of the Applicant

13.1.2 Operating Organization

In Chapter 13 of FSAR Amendment 21 (submitted by letter from M. R. Edelman to B. J. Youngblood dated October 4, 1985), the applicant documented organizational changes reflecting how the plant organization and staff would function during Perry Unit 1 operations phase. On the basis of its review of this information, the staff identified the following items as requiring clarification and/or supplemental information to determine the acceptability of the organizational changes:

(1) a clear description of the individual who will be the Plant Manager;

(2) confirmation that the designated Plant Manager will have direct access to all of the functional elements in the organization necessary to safely operate the plant during normal operation, and to mitigate safety impacts during abnormal or emergency operations; and

(3) documentation of the qualification of key operations and technical support staff responsible for safety-related functions.

These concerns were made known to the applicant and a meeting was held in the NRC offices in Bethesda, Maryland on October 31, 1985 to resolve the concerns. At the meeting, the applicant's representatives supplied additional information by letter dated October 29, 1985 (M. R. Edelman to B. J. Youngblood), entitled "Plant Organization."

In that letter the applicant:

(1) designated the position of Manager, Perry Plant Operations Department as the single position in its organization responsible for fulfilling the responsibilities of the Plant Manager;

(2) provided copies of internal operating procedures (POP-0105 and PAP-0104) which clearly stated that authority assigned to the Manager of the Perry Plant Operations Department to fulfill the responsibilities of the Plant Manager (this authority includes the right at any time to direct any and all resources of the other elements within the Nuclear Operations Division for the safe operation of the plant);

(3) provided copies of qualification statements for the missing operational and technical support staff who would be performing safety-related duties within the plant.

The staff has since completed its final review of Chapter 13, FSAR Amendment 21 and the supplemental information provided in the applicant's October 29, 1985 letter, and concludes that the plant operating organization proposed by the

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applicant acceptably meets the acceptance critria for Regulatory Guide 1.8 and the Standard Review Plan, NUREG-0800.

13.1.2.5 Fire Brigade

Section 13.1.2.5 of the SER is revised in this supplement to reflect the applicant's current plans for fire brigade staffing and training, documented in the applicant's letter dated March 25, 1985 (M. R. Edelman to B. J. Youngblood), and found acceptable by the staff.

A fire brigade consisting of a brigade leader with either a reactor operator's license or equivalent knowledge of plant safety-related systems (simulator certification with plant systems familiarity) and four Security personnel will be available on all shifts. Two of the four Security personnel shall have sufficient training in or knowledge of plant safety-related systems to understand the effect of fire and fire suppressants on safe shutdown capability. The fire brigade members will have no duties during a fire except those directly related to manual fire-fighting. Before being assigned to the fire brigade and annually thereafter, each member will receive a physical examination that will ensure no physical condition exists that would prevent proper performance of strenuous fire-fighting activities.

The fire brigade will be equipped with sufficient quantities of personal protective equipment, manual suppression equipment and other equipment necessary for effective fire-fighting. Equipment will meet criteria stipulated in 10 CFR 50, Appendix R, Section H.

The fire brigade training program provides for classroom training, practice sessions, and drills. The fire brigade training program will meet criteria stipulated in 10 CFR 50, Appendix R, Section III.I. With regard to Section III.I.3.b, drills shall be performed at least quarterly per shift with intervening intervals no more than 5 months nor less than 1 month for any given shift. A number of onshift personnel will receive the same basic training as that received by the fire brigade. Additionally, a substantial number of onshift personnel will receive incipient fire-fighting training. These personnel will be available to assist the fire brigade.

13.3 Emergency Plan

The staff has completed its review and evaluation of the adequacy of the applicant's radiological emergency response plan (Plan) (through Revision 5). The results of this evaluation are given in Section 13.3.2 below. The staff's findings are discussed under the same headings and numbering system used in SSER 6. Section 13.3.3 addresses offsite emergency planning medical services. Section 13.3.4 provides the Federal Emergency Management Agency's (FEMA's) evaluation of offsite emergency preparedness for Perry. Section 13.3.5 addresses the status of the hearing on emergency preparedness issues. Section 13.3.6 provides the staff's conclusions.

13.3.1 Background

SSER 6 provided the staff's review and evaluation of the applicant's Plan through Revision 4. In SSER 6, the staff identified confirmatory items that

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had not been fully resolved. On August 6, 1985, the applicant submitted Revision 5 to the Plan.

13.3.2 Evaluation of the Emergency (Onsite) Plan

13.3.2.4 Review of Upgraded Emergency Action Levels

The staff has reviewed the upgraded emergency action level (EAL) scheme contained in Revision 5 to the Plan, submitted by the applicant on August 6, 1985, and finds that it conforms to the guidance criteria of Appendix 1 to NUREG-0654, Revision 1.

13.3.2.5 Testing and Demonstration Operability of the Siren System

NRC Region III has identified the operability of the entire siren system as an item which must be demonstrated prior to fuel load (see Inspection Report Open Items 440/85009-25; 441/85007-25). Accordingly, Region III will provide confirmation in a followup inspection report that the siren system has been installed and its operability has been tested. This planning item is closed.

13.3.2.10 Protective Response--Further Evaluation of Comments by State and Local Officials on the Evacuation Time Estimate Study

By letter dated April 22, 1985 (B. J. Youngblood to M. R. Edelman), the staff requested that the applicant furnish its response to each of the comments provided by State and local officials and the draft evacuation time estimate (ETE) study, indicating which comments were incorporated and which were not, including the applicant's reason for not incorporating said comment.

By letter dated May 22, 1985 (M. R. Edelman to B. J. Youngblood), the applicant responded to the staff's request. The applicant provided a detailed discussion on each ETE comment, indicating its final resolution. Each of the comments was considered in the review and update of the ETE study. Almost all of the comments were incorporated. If a comment was not incorporated, the applicant provided an acceptable reason for its exclusion. The applicant specified that each agency indicated satisfaction both with the resolution of its comments and with the February 1985 ETE study. In addition, these comments were discussed via telephone with the applicant on June 10 and 17, 1985.

On the basis of the applicant's submittal of May 22, 1985, and subsequent discussions with the applicant on comments not incorporated, the staff finds this portion of the applicant's Plan adequate.

13.3.3 Offsite Emergency Planning Medical Services

In a recent decision, GUARD v. NRC, 753 F.2d 1144 (D.C. Cir. 1985), the U.S. Court of Appeals vacated the Commission's interpretation of 10 CFR 50.47(b)(12) to the extent that a list of facilities was found to constitute adequate arrangements for medical services for members of the offsite public exposed to dangerous levels of radiation. The Commission has now provided guidance to be followed in ascertaining compliance with this regulation pending its determination of how it will proceed in response to the Court's remand. In particular, the Commission directed that Licensing Boards, and in uncontested cases, the staff, should

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consider the uncertainty attendant the Commission's interpretation of this regulation, especially in regard to its interpretation of the term "contaminated injured individuals." In GUARD, the Court left open to the Commission the discretion to reconsider whether that term should include members of the offsite public exposed to dangerous levels of radiation and, thus, whether arrangements for this population of individuals are required at all. For this reason, the Commission observed that it may reasonably be concluded that "no additional actions should be taken now on the strength of the present interpretation of that term." Accordingly, the Commission observed that it can be found "that any deficiency which may be found in complying with a finalized post-GUARD planning standard (b)(12) is insignificant for the purposes of 10 CFR 50.47(c)(1)." In this regard, the Commission, as a generic matter, noted the low probability of accidents that might result in exposure of members of the offsite public to dangerous levels of radiation as well as the slow development of adverse reactions to overexposure. (See Emergency Planning, Statement of Policy, 50 FR 20892, May 21, 1985).

Consistent with the foregoing Statement of Policy, the applicant has, by letter dated July 25, 1985 (M. R. Edelman to B. J. Youngblood), confirmed that the emergency plans of the involved offsite response jurisdictions contain a list of medical service facilities. The existence of such a list in the pertinent plans has also been confirmed by FEMA. Further, the applicant has committed to fully comply with the Commission's response to the Court's remand.

Accordingly, on the basis of the factors identified by the Commission in its Statement of Policy, the staff has determined that the requirements of 10 CFR 50.47(c)(1) have been satisfied so as to warrant issuance of the operating license pending further action by the Commission with respect to the requirements of 10 CFR 50.47(b)(12).

13.3.4 Federal Emergency Management Agency's Report on Offsite Preparedness

The FEMA interim finding of March 1, 1984, which was provided in Appendix L to SSER 5, stated that there is reasonable assurance that State and local plans are adequate and capable of being implemented. An exercise to test these plans was held on November 28, 1984. On January 31, 1985, FEMA reported that there were no Category A deficiencies identified as a result of the exercise. On May 23, 1985, FEMA reported that the State of Ohio's schedule of corrective actions for the lesser deficiencies identified in the exercise was adequate.

13.3.5 Atomic Safety and Licensing Board Hearings on Emergency Preparedness

A hearing on emergency preparedness issues before the Atomic Safety and Licensing Board (ASLB) was held on April 9-12, 1985. On September 3, 1985, the ASLB issued its decision authorizing the issuance of an operating license for Perry Units 1 and 2, provided the applicant demonstrates satisfactory completion of the following conditions related to emergency preparedness:

(1) The applicant's EALs conform to the initiating guidance of NUREG-0654, Appendix 1.

(2) Letters of agreement have been obtained from all school districts for the supply of buses for evacuation purposes.

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(3) Training of fire personnel in monitoring and decontamination procedures is complete and all reception centers are provided with necessary decontamination equipment.

(4) The applicant has committed in writing to comply with the Commission's response to the remand in GUARD v. NRC 753 F.2d 1144 (D.C. Cir. 1985).

Conditions 1 and 4 have been met and are discussed in Sections 13.3.2.4 and 13.3.3, respectively, of this supplement. With regard to Conditions 2 and 3, the staff has requested that FEMA provide confirmation that these two conditions have been met. The staff's evaluation of FEMA's response will be provided in a future supplement to the SER. Resolution of Conditions (2) and (3) are being added as License Condition (31) in this supplement.

13.3.6 Conclusions

On the basis of the staff's review of the applicant's radiological emergency plan, the staff concludes that the emergency plan provides an adequate planning basis for an acceptable state of onsite emergency preparedness and meets the requirements of 10 CFR 50 and Appendix E thereto. FEMA has provided an interim finding on the State and local emergency plans and a report of the full participation exercise. On the basis of the staff's review of the applicant's emergency plans and procedures, the NRC and FEMA evaluation of the full participation exercise, and the staff's review of the FEMA finding on State and local emergency plans, the staff concludes that the state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Final resolution of Conditions 2 and 3 of the ASLB September 3, 1985 Decision, as confirmed by FEMA, will be provided in a future supplement to the SER.

13.5 Plant Procedures

13.5.2 Operating and Maintenance Procedures

13.5.2.4 Operability Status Procedures

In Section 13.5.2.4 of the SER, the staff required, as a condition for issuing any operating license for Perry, that the existence of procedures for the removal of safety-related systems from service in accordance with the provision of TMI Action Plan Item II.K.1.10 be verified. The staff has since verified that controls have been instituted to ensure that critical valve operability status is known and related procedures have been implemented by the applicant. Consequently, SER License Condition (12) is being deleted in this supplement.

13.6 Physical Security

As a result of the staff's review of the revisions for the previously approved security contingency and guard training and qualification plans, which incorporate Revision 4 to the Physical Security Plan for the Perry Nuclear Power Plant Unit 1, License Condition (13), stated in Section 1.11 of the SER and in SSER Nos. 1 through 6, is updated in Section 1.11 of this supplement. The approved security plans for Perry Unit 1 consist of the following:

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(1) Security Plan

Submittal 1, undated (transmittal letter dated January 28, 1981) as revised by:

- Submittal 2, undated (transmittal letter dated February 25, 1982)
- Revision 3, dated March 1, 1982 (transmittal letter dated March 22, 1982)
- Revision 4, dated May 1, 1985 (transmittal letter dated May 15, 1985)

(2) Safeguards Contingency Plan (Chapter 8 of the Security Plan)

Submittal 1, undated (transmittal letter dated January 28, 1981) as revised by:

- Revision 1, dated July 31, 1981 (transmittal letter dated July 31, 1981)
- Revision 2, dated November 30, 1981 (transmittal letter dated November 25, 1981)

(3) Security Force Training and Qualification Plan

Submittal 1, undated (transmittal letter dated January 28, 1981) as revised by:

- Revision 1, dated July 31, 1981 (transmittal letter dated July 31, 1981)
- Revision 2, dated January 8, 1982 (transmittal letter dated January 8, 1982)

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14 INITIAL TEST PROGRAM

In Section 14 of the SER, the staff reported the results of its review of the applicant's initial test program as documented in the FSAR through FSAR Amendment 6. SER Section 14 is further updated to reflect the results of the staff's review of changes reflected in FSAR Amendments 7 through 17, including questions raised and responded to by the applicant in letters dated April 2, April 29, June 21, and June 28, 1985 (M. R. Edelman to B. J. Youngblood).

In FSAR Amendment 17, the applicant documented his exception to the provision for 2 hours' testing at 110% of rated load required in Section C.2.a.(3) of Regulatory Guide (RG) 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants." The staff believed that the rationale supporting the exception should be clarified. The applicant stated that the standby diesel generator (SDG) units (Divisions I and II) shall demonstrate full-load carrying for an interval of not less than 24 hours at a load equivalent to the continuous ratings of each SDG. The applicant further noted that the continuous rating exceeds both the maximum accident load and the maximum load required for forced shutdown; and, therefore, the 24-hour testing at rated load is an adequate demonstration of the SDG capabilities.

The SDGs at a number of nuclear power plants including Perry are under review by the staff and have special operating restrictions because of problems experienced with the diesel generators of their particular vendor. These plants all have Transamerica Delaval, Inc. (TDI), diesel generators. The TDI problem and status with respect to Perry is discussed in detail in SSER No. 6, and TDI diesel engine testing is further updated in Section 8.3.1 of this supplement.

The staff has not completed its review of the adequacy of the Perry crankshafts for their rated load (7000 kW and overload 7700 kW) capacities. However, the staff has concluded in the interim that the Perry crankshafts have a load capacity of at least 5740 kW which exceeds the maximum emergency service load requirements for these engines.

Limiting preoperational testing to 7000 kW, as proposed by the applicant, would reduce the potential for damaging the crankshaft while providing a conservative test relative to the maximum emergency load requirement. For this reason, the staff approves the proposed exception to the 2-hour-overload test. The proposed preoperational test program will still exceed the interim 5740-kW load capacity estimate; therefore, the staff is requiring that preoperational testing involving operation in excess of 5740 kW shall be followed by a crankshaft inspection to verify that the crankshafts are free of damage as stated in the staff's letter dated March 25, 1985 (B. J. Youngblood to M. R. Edelman). (See Section 8.3.1 of this supplement for discussion of TDI diesel engine testing requirements.) Accordingly, Confirmatory Issue (62) is considered to be resolved.

Section 14 of SSER No. 1 delineated as a part of the initial test program, the objectives of the simulated-loss-of-all-ac-power or station blackout (SBO) test.

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By NRC Generic Letter 83-24, TMI Task Action Plan Item I.G.1, "Special Low Power Testing and Training, Recommendations for BWRs," applicants for an operating license were requested to commit to the recommendations of the BWR Owners Group with respect to this additional testing, and to respond to the Generic Letter demonstrating that a proposed SBO test would have the risk of damaging plant equipment.

The Cleveland Electric Illuminating Company (CEI or the applicant) submitted the results of its evaluation of the SBO event by letter dated September 12, 1985 (M. R. Edelman to B. J. Youngblood). From the results of that evaluation, CEI concluded that conducting an SBO test would pose a potential risk for damaging equipment as a result of high temperatures in the drywell.

Although the CEI analyses lacked a discussion of plant-specific assumptions or results, the similarity of Perry with other BWR plants is sufficient to assure the staff that the Perry results are consistent and acceptable. For example, the Clinton nuclear plant, a similar BWR-6, with thermal power level of 2894 MWt and drywell volume of 246,500 cubic feet, compares with Perry at a thermal power level of 3579 MWt and a drywell volume of 278,000 cubic feet. The temperature responses of the plants to the SBO event are nearly identical and the staff has previously accepted the Clinton evaluation. The Perry SBO results and conclusions are also consistent with Susquehanna, Hope Creek, LaSalle, and other BWRs. Therefore, the staff concludes that the SBO test need not be performed at Perry Nuclear Power Plant because of the potential risk of damage to non-safety-related equipment in the drywell. Since Perry Nuclear Power Plant has committed to the BWR Owners Group recommendations for augmented testing, the staff also concludes that the Perry Nuclear Power Plant Test Program described in the FSAR, without the SBO test, meets the TMI Action Plan Item I.G.1 requirements.

By letter dated September 18, 1985 (M. R. Edelman to B. J. Youngblood), the applicant proposed deletion of the main steam isolation valve (MSIV) leakage control system test (FSAR Subsection 14.2.12.2.59) from the startup test program, since all of the test objectives will be completed during the preoperational test (FSAR Subsection 14.2.12.1.17). The staff finds it acceptable to delete redundant testing such as that proposed by the applicant, and has consistently done so with other reactor plant test programs (e.g., Fermi-2 and Grand Gulf Nuclear Station). Long periods between preoperational testing and the actual plant operation are normally covered by routine performance of the surveillance test for the MSIV leakage control system or in the performance of required surveillance tests just prior to initial plant startup.

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16 TECHNICAL SPECIFICATIONS

The ability of the Perry reactor coolant system relief and safety valves to function under expected operating conditions for design-basis transients and accidents, as defined in TMI Action Plan Item II.E.4.2 Subitem (f) (NUREG-0737), has been found acceptable by the staff with the condition that the 42-inch purge valves be limited to a 50-degree opening angle, and that this limitation be required in the Perry Technical Specifications as appropriate. (See Section 3.9.3.2.1 of this supplement for the technical basis upon which conformance with the provisions of TMI Action Plan Item II.E.4.2(f) is predicated.) This requirement is accordingly being added to the list of SER Technical Specification items, in addition to the Standard BWR/6 Technical Specifications. A composite list of the additional items follows, including this new item. The SER/SSER section in which each item is discussed is indicated in parentheses:

(1) response time testing (SER, Section 7.2.2.6)

(2) systems shared by Units 1 and 2 (SER and SSER 4, Section 7.3.4.2)

(3) single-loop operation subject to staff approval of supporting analysis (SER, Section 4.4.4)

(4) operation in natural circulation mode subject to completion of the staff's generic evaluation of thermal-hydraulic stability for BWRs (SER, Section 4.4.4)

(5) core flow to be checked by the applicant at least once every 24 hours to account for possible buildup of crud deposition (SER, Section 4.4.5)

(6) availability, setpoints, and frequency of surveillance requirements to be imposed for Level 8 trip and turbine bypass equipment to ensure an acceptable level of performance for anticipated operational transients (SER and SSER 6, Section 15.1)

(7) surveillance of the low-pressure air alarm systems to ensure that the backup air system will provide continued inventory of air to actuate the ADS valves, if they are needed (SER, SSER 2, and SSER 4, Section 6.3.1.3)

(8) use of the ADS logic manual initiation switch (SER, SSER 2, and SSER 4, Section 6.3.1.3)

(9) leakage integrity tests of the isolation valves in the containment purge/vent system to be conducted at least once every 3 months for active valves, and once every 6 months for inactive valves; and operation of the 18-inch supply/exhaust lines shall be limited to 3000 hours, with the two 42-inch inbound isolation valves in an appropriately sealed-closed condition, during the plant's first operating fuel cycle (SSER 4, Section 6.2.4).

(10) limit 42-inch purge valves to 50-degree opening angle during plant operating modes (SSER 7, Section 3.9.3.2.1)

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17 QUALITY ASSURANCE

17.2 Quality Assurance During the Operations Phase

17.2.1 General

The description of the quality assurance (QA) program for the operations phase of Perry is contained in FSAR Section 17.2. Evaluation of the Perry QA program is based on a review of this information and discussions with representatives of the applicant, the Perry Resident Inspector, and the NRC Region III Office. The staff assessed the applicant's QA program through FSAR Amendment 18 for the operations phase to determine whether it complies with the requirements of 10 CFR 50, Appendix B, the applicable QA-related regulatory guides listed in Table 17.1, and the Standard Review Plan (NUREG-75/087), Revision 1, Section 17.2, "Quality Assurance During the Operations Phase." This section supersedes all previous Section 17.2 statements on the Perry Nuclear Power Plant.

Since this review effort, the Standard Review Plan was updated to Revision 2 (NUREG-0800). An additional review, conducted to determine the extent to which the applicant's QA program meets Revision 2, shows that the QA program complies with Revision 2, except for the following controls, to which no clear commitment is provided.

The program does not specify:

(1) criteria for determining the size of the QA organization, including the inspection staff (NUREG-0800, Section 17.1, item 1A5)

(2) that the QA organization participates early in the QA program definition stage to determine and identify the extent to which QA controls are to be applied to specific structures, systems, and components. This effort involves applying a defined, graded approach to certain structures, systems, and components in accordance with their importance to safety and affects such disciplines as design, procurement, document control, inspection tests, special processes, records, audits, and other disciplines described in 10 CFR 50, Appendix B (NUREG-0800, Section 17.1, item 2B3)

(3) that procedures are established and described which require a documented check to verify the dimensional accuracy and completeness of design drawings and specifications (NUREG-0800, Section 17.1, item 3E1)

(4) that program procedures provide criteria for determining the accuracy requirements of inspection equipment and criteria for determining when inspections are required to define how and when inspections are performed. The QA organization must participate in these functions (NUREG-0800, Section 17.1, item 10A).

As elaborated below, QA controls generally provide for increased involvement of the QA organization in certain quality-related activities and increase emphasis on the need for procedures, documentation, and requirements for other

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quality-related activities. As such, the staff believes that adequate QA controls in these areas are already included in the Perry QA program and that the additional items listed above (from NUREG-0800) need not be mandatory at this time.

17.2.2 Organization

The structure of the organization responsible for operating Perry and for establishing and executing the operations-phase QA program is shown in Figure 17.1, Revision 2. The Perry Quality Assurance Department Organization is shown in Figure 17.2.

The Nuclear Group Vice President has the overall responsibility for the safe and reliable operation of the Perry plant. The Nuclear Quality Assurance Department Manager (NQADM), who reports directly to the Nuclear Group Vice President, has been delegated authority for establishing the QA program requirements, verifying their implementation, and measuring the overall effectiveness of the program. The NQADM, or designated alternate, has responsibility and authority to stop unsatisfactory work and control further processing, delivery, or installation of nonconforming material during plant operation, maintenance, modification, construction, and inservice inspection. The Operations Quality Section, the Procurement and Administration Quality Section, the Construction Quality Section, and the Audit Unit report directly to the NQADM.

The Operations Quality Section provides quality support and verification to the operating plant unit. Activities include (1) input to and review of safety-related work authorization, (2) procedures and corrective documents, (3) coordination of nondestructive examination support for inservice inspection, (4) inspection and maintenance and modification, and (5) maintenance of the operations QA plan.

The Procurement and Administration Quality Section (1) reviews and approves procurement documents; (2) maintains a program for approval, audit, and surveillance of suppliers; (3) performs receipt inspections; and (4) provides nondestructive examination service and administrative support for the department.

The Construction Quality Section is responsible for coordinating site quality functions associated with construction and providing QA coordination and support for outages during Unit 1 operation.

The Audit Unit is responsible for providing a system of planned and periodic internal audits, and for effectively implementing this system.

The QA organization has the authority (1) to identify quality-affecting problems in order to initiate, recommend, or provide solutions through designated channels; (2) to verify implementation of solutions; (3) to stop unsatisfactory work; and (4) to control further processing, delivery, or installation of nonconforming items. It is also responsible for:

(1) reviewing and concurring with documents (i.e., procedures and instructions) affecting safety

(2) verifying surveillance of inplant activities

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(3) performing inspections and examinations associated with operations-phase activities

(4) performing pre-award evaluation of suppliers, and surveillance and inspection at supplier's facilities

(5) ensuring that personnel qualifications are current and are applicable to the work being performed

(6) ensuring that corrective actions are effective and are accomplished in a timely manner

(7) conducting internal audits of maintenance, modification, and operations activities, and external audits of suppliers

The Nuclear Quality Assurance Department will also audit and supply instructors to the Nuclear Project Training organization of the Perry Project Service Department.

17.2.3 Quality Assurance Program

The QA program for the operation of Perry is described in FSAR Section 17.2 and is implemented by means of written policies, procedures, and instructions. The applicant has committed to follow the provisions of the applicable QA-related regulatory guides listed in Table 17.1. during the operations phase.

The QA organization is responsible for assuring that procedures and instructions completely and adequately satisfy QA requirements. In addition, QA personnel conduct reviews, inspections, and audits to verify the effective implementation of the QA program.

The applicant's QA program requires that implementing procedures and instructions encompass detailed controls for (1) translating codes, standards, regulatory requirements, Technical Specifications, and engineering and process requirements into drawings, specifications, procedures, and instructions; (2) developing, reviewing, and approving procurement documents, including changes; (3) prescribing all quality-related activities by documented instructions, procedures, drawings, and specifications; (4) issuing and distributing approved documents; (5) purchasing items and services; (6) identifying materials, parts, and components; (7) performing special processes; (8) inspecting and testing materials, equipment, processes, or services; (9) calibrating and maintaining measuring and test equipment; (10) handling, storing, and shipping items; (11) identifying the inspection, test, and operating status of items; (12) identifying and correcting or disposing of nonconforming items; (13) correcting conditions adverse to quality; (14) preparing and maintaining quality assurance records; and (15) auditing activities that affect quality.

The indoctrination and training program established by the NQADM ensures that personnel performing activities affecting quality are knowledgeable in QA requirements, implementing procedures, and instructions, and that they have competence and skill in performing their quality-related activities. The program provides for any necessary retraining of personnel performing activities that affect quality.

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Quality is verified through checking, review, surveillance, inspection, testing, and auditing of quality-related activities. The QA program requires that quality verification be performed by individuals who are not directly responsible for performing the quality-related activities. Inspections are performed by qualified personnel in accordance with procedures, instructions, and checklists approved by the QA organization.

The QA organization is responsible for the establishment and implementation of the audit program. Audits are performed in accordance with pre-established written checklists by qualified personnel not having direct responsibilities in the areas being audited. Periodic audits will be performed by the Nuclear Quality Assurance Department to evaluate all aspects of the QA program including the effectiveness of the program's implementation. The QA program requires that the person having responsibility in the area audited review the audit results and take any corrective action determined to be necessary. Followup audits are performed to determine that nonconformances and deficiencies are effectively corrected and that the corrective action precludes repetitive occurrences. Audit reports, which indicate performance trends and the effectiveness of the quality assurance program, are prepared and issued to responsible management for personnel review and assessment.

17.2.4 Conclusions

On the basis of its review and evaluation of the QA program description in Section 17.2 of the FSAR, the staff concludes that

(1) The applicant's organization gives QA personnel sufficient independence from cost and schedule (when opposed to safety considerations), authority to effectively carry out the operations QA program, and access to management at a level necessary to perform the QA functions.

(2) The QA program describes requirements, procedures, and controls that, when properly implemented, comply with the requirements of Appendix B to 10 CFR 50, and with the acceptance criteria contained in NUREG-75/087, Section 17.2, Revision 1.

Accordingly, the staff concludes that the applicant's description of the QA program, if properly implemented, is in compliance with applicable regulations.

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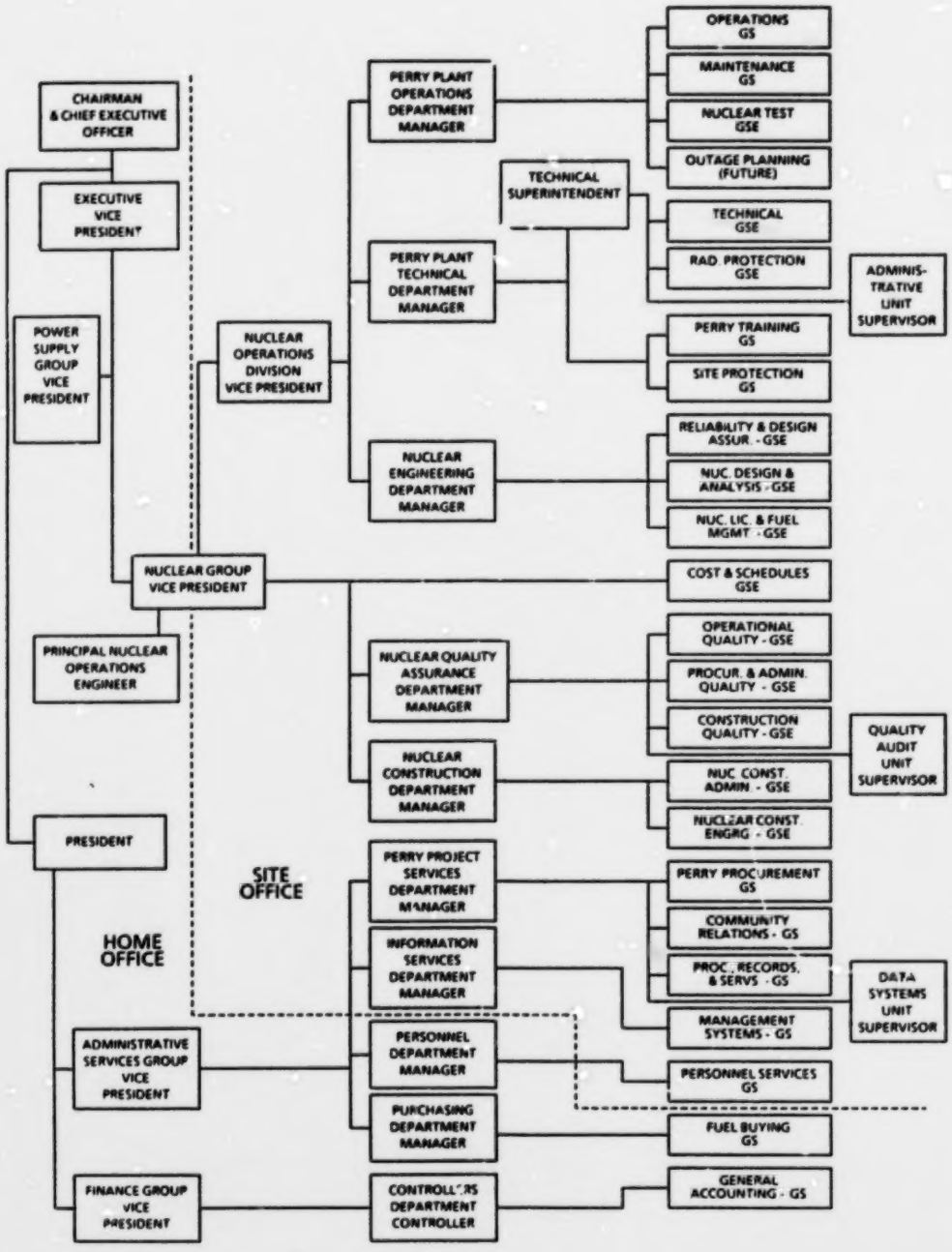

Figure 17.1 Perry Nuclear Power Plant project organization (Rev. 2)
Source: Figure 13.1-2, FSAR Amendment 18, April 10, 1985

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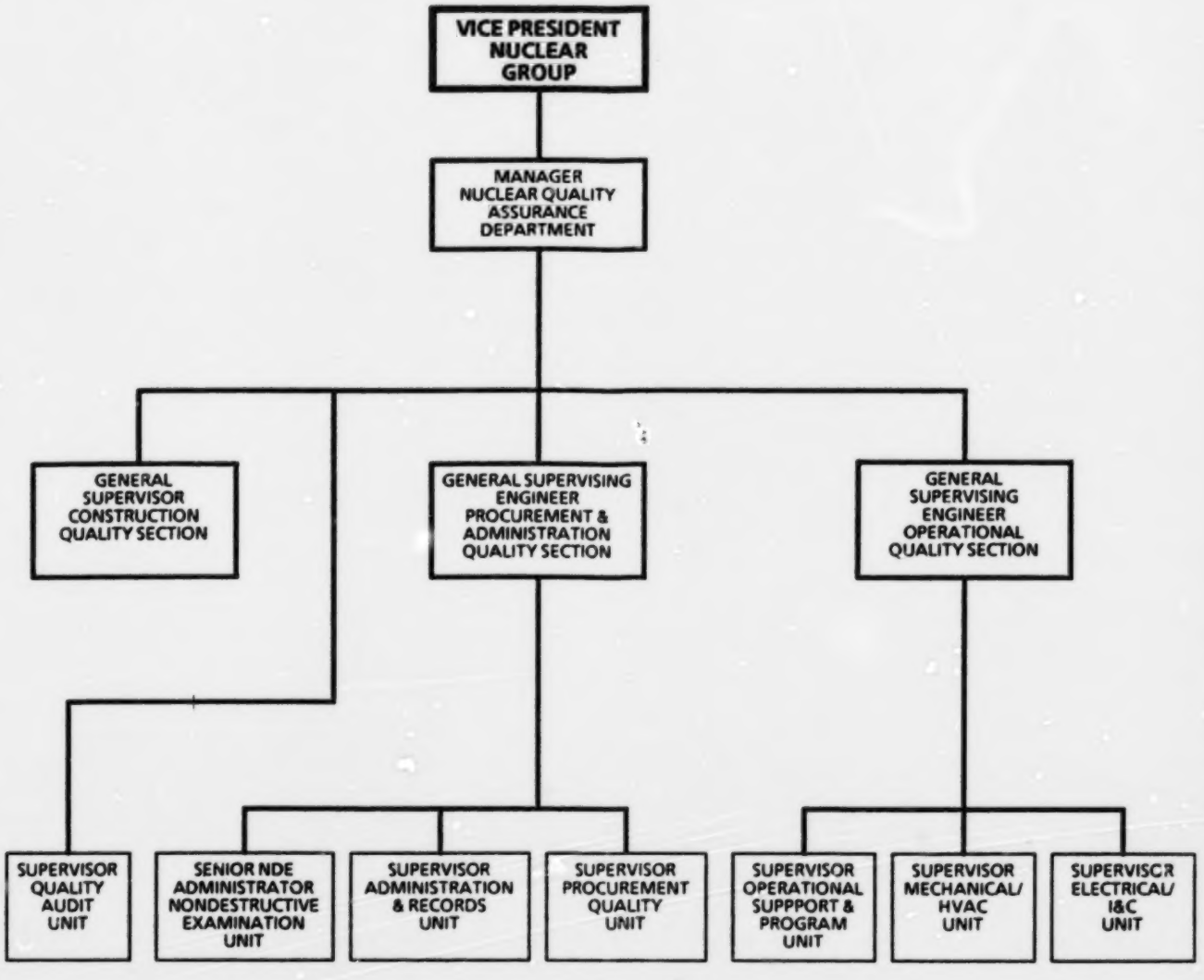
VICE PRESIDENT NUCLEAR GROUP
MANAGER NUCLEAR QUALITY ASSURANCE DEPARTMENT
GENERAL SUPERVISOR CONSTRUCTION QUALITY SECTION
GENERAL SUPERVISING ENGINEER PROCUREMENT & ADMINISTRATION QUALITY SECTION
GENERAL SUPERVISING ENGINEER OPERATIONAL QUALITY SECTION
SUPERVISOR QUALITY AUDIT UNIT
SENIOR NDE ADMINISTRATOR NONDESTRUCTIVE EXAMINATION UNIT
SUPERVISOR ADMINISTRATION & RECORDS UNIT
SUPERVISOR PROCUREMENT QUALITY UNIT
SUPERVISOR OPERATIONAL SUPPPORT & PROGRAM UNIT
SUPERVISOR MECHANICAL/ HVAC UNIT
SUPERVISOR ELECTRICAL/ I&C UNIT

Figure 17.2 Nuclear Quality Assurance Department organization
Source: Figure 17.2-2, FSAR Amendment 14, August 22, 1984

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Table 17.1 Regulatory guides applicable to quality assurance program (revised from Table 17.1 in the SER)

Reg. Guide	Rev. no.	Date	Title
1.8	1-R	5/77	Personnel Selection and Training (draft)
1.26	3	3/76	Quality Group Classifications and Standards for Water-, Steam-, and Radio-Waste-Containing Components of Nuclear Power Plants
1.29	3	9/78	Seismic Design Classification
1.30	-	8/11/72	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment
1.33	2	3/78	Quality Assurance Program Requirements (Operations)
1.37	-	3/73	Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants
1.38	2	5/77	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants
1.39	2	9/77	Housekeeping Requirements for Water-Cooled Nuclear Power Plants
1.58	1	9/80	Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel
1.64	2	6/76	Quality Assurance Requirements for the Design of Nuclear Power Plants
1.74	-	2/74	Quality Assurance Terms and Definitions
1.88	2	10/76	Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records
1.94	1	4/76	Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
1.116	0-R	5/77	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems
1.123	1	2/78	Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
1.144	1	9/80	Auditing of Quality Assurance Programs for Nuclear Power Plants
1.146	-	8/80	Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

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18 CONTROL ROOM DESIGN REVIEW

18.2 Evaluation of DCRDR Program Plan Report

Cleveland Electric Illuminating Company (the applicant) submitted program plan information for the Perry Nuclear Power Plant (Perry) Unit 1 detailed control room design review (DCRDR) in letters dated June 7, 1982 (D. R. Davidson to A. Schwencer); April 15, 1983 (M. R. Edelman to B. J. Youngblood); and June 21, 1983 (M. R. Edelman to B. J. Youngblood). NRC forwarded staff comments on the program plan information to the applicant on December 23, 1983 (B. J. Youngblood to M. R. Edelman). On the basis of the staff's review of information in the June 7, 1982 submittal, an in-progress audit was conducted August 9-13, 1982.

The applicant submitted the Perry Unit 1 DCRDR Summary Report on January 10, 1985 (letter from M. R. Edelman to B. J. Youngblood). On the basis of review of the Summary Report and on the results of previous activities, the NRC staff planned a preimplementation audit of the Perry Unit 1 DCRDR. That audit was conducted from April 8 to 12, 1985. A second preimplementation audit was conducted September 10-13, 1985 because of concerns about the applicant's progress in implementing corrections to human engineering discrepancies (HEDs).

The applicant is committed to prelicensing completion of the DCRDR (including review of the remote shutdown panel) and to prelicensing correction of a large number of human engineering discrepancies (HEDs). Staff evaluation of the Perry Unit 1 DCRDR follows. The evaluation is based on information available to date and is arranged in order of the DCRDR elements identified in Supplement 1 to NUREG-0737. The staff was assisted in its evaluation by Lawrence Livermore National Laboratory (LLNL). The LLNL technical evaluation report (TER), which gives a detailed evaluation of the Perry Unit 1 DCRDR, is being added to the SER in this supplement as Appendix P. Appendices A and B of the TER are superseded in this supplement in Table 18.1. Appendix C of the TER in also superseded by Table 18.1 insofar as it refers to correction status of HEDs. With the above-noted exceptions, the staff concurs with the evaluations and conclusions in the TER. A synopsis of the staff's position on the Perry Unit 1 DCRDR is provided below.

18.2.1 Establishment of a Qualified Multidisciplinary Review Team

A qualified multidisciplinary review team has been established for the Perry Unit 1 DCRDR. The applicant should ensure continued participation of personnel from appropriate disciplines, including human factors and operations, during the remainder of the DCRDR in order to complete this element.

18.2.2 Use of Function and Task Analyses

The applicant will use Perry Plant Emergency Instructions (PEIs - equivalent to emergency operating procedures at other plants) as the basis for identifying control room tasks and information and control requirements during emergency operations. The PEIs have been developed using the Boiling Water Reactor Owners Group (BWROG) Emergency Procedure Guidelines (EPGs). The applicant's approach

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can have acceptable results, but success depends on the development of complete and technically adequate PEIs. The staff understands that final revision of the PEIs to be implemented before fuel load is under way. The staff further understands that the applicant will update the task analysis on the basis of that revision of the PEIs. The update should identify new and modified tasks, the information and control capabilities needed to perform those tasks, and the displays and controls (including appropriate characteristics) required to satisfy those needs. This element of the DCRDR should be satisfied when the task analysis has been updated. The applicant should indicate the revision of the BWROG EPGs upon which the definitive PEIs are based.

18.2.3 Comparison of Display and Control Requirements With Control Room Inventory

The organization, process, and current results of this DCRDR element are acceptable. This element of the DCRDR should be satisfied when the control room inventory has been compared with the results of the update of the task analysis discussed in the Section 18.2.2 above.

18.2.4 A Control Room Survey

The organization, process, and current results of the control room survey to identify deviations from accepted human factors principles are acceptable. This element of the DCRDR should be satisfied when communications equipment and environmental conditions in the finished control room and remote shutdown panel have been surveyed.

18.2.5 Assessment of HEDs

The applicant's DCRDR for Perry Unit 1 used an "integrated assessment methodology" that combined HED assessment and selection of design improvements. The method was not consistent with NRC guidelines in that an independent determination of whether a HED should be corrected (based on error potential and error consequence) was not made. The applicant's method did, however, review all HEDs which, following initial assessment, were to remain uncorrected or partially corrected. The followup review was performed in terms of plant safety and operability. If there was a significant consequence to leaving a HED uncorrected or partially corrected, that HED was iteratively subjected to selection of design improvements and assessment until the problem was resolved. The applicant's integrated assessment methodology produced acceptable results with respect to the HED assessment element of the DCRDR. This element should be satisfied when HEDs identified by comparison of the control room inventory with results of the updated task analysis and HEDs identified by the remaining control room survey activities have been assessed.

18.2.6 Selection of Design Improvements

The selection-of-design-improvements process, which was part of the integrated assessment methodology, is acceptable. This element of the DCRDR should be satisfied when design improvements have been selected for safety-significant HEDs identified by the comparison of the control room inventory with the results of the updated task analysis and by remaining control room survey activities.

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18.2.7 Verification That Selected Improvements Provide the Necessary Correction and Do Not Introduce New HEDs

Verification activities were performed by an independent team which included a human factors specialist, a licensed shift supervisor, and a senior design engineer. That group reviewed revised panel drawings against Boiling-Water Reactor Owners Group (BWROG) panel survey checklists. The staff is concerned that a drawing review, by itself, can not ensure that new HEDs will not be introduced because such a review does not permit sufficient evaluation of how all proposed corrections work together. In the staff's judgment, the verification activities should be augmented. Further indication that verification activities should be augmented is provided in Appendix D of the appended TER (Appendix P of the SER introduced in this supplement). Appendix D of the TER lists a number of staff recommendations developed by the preimplementation audit team during its evaluation of DCRDR results.

HED corrections have not been completed. The TER recommends that the applicant conduct a followup survey in the control room when those corrections are complete. A hands-on walkthrough/talkthrough of finalized PEIs is also recommended. In the staff's judgment, the above recommendations provide appropriate means for augmenting the existing verification processes. The applicant should also assess the significance of concerns identified in Appendix P and select and verify design improvements that resolve those concerns. The major thrust of the applicant's verification activities should be to ensure a consistent, coherent, and effective control room interface with operators.

18.2.8 Coordination of Control Room Improvements With Other Programs

Coordination of control room improvements with changes from other programs, such as the safety parameter display system (SPDS), operator training, RG 1.97 (Rev. 2) instrumentation, and upgraded emergency operating procedures, is acceptable. The applicant should ensure that coordination continues through the remainder of the DCRDR in order to complete this element.

18.3 Summary Report Requirements

The applicant provided information on 334 HEDs and their proposed disposition as part of the Summary Report. The staff reviewed the status of those HEDs during the preimplementation audits. The status of HED corrections, based on those audits, is provided in Table 18.1 and is summarized as follows:

A.	HEDs which have been corrected and are closed	182
B.	HEDs to be corrected by licensing	
1.	Open pending implementation of correction	61
2.	Open pending additional review, revised response, and implementation of correction	17
3.	Open pending revised response - additional review and implementation complete	39

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C. HEDs for which partial or interim corrections will be implemented by licensing and which will be completely corrected by the end of the first refueling outage

1.	Open pending implementation of partial or interim correction	6
2.	Open pending additional review, revised response, and implementation of partial or interim response	1
3.	Open pending revised response - additional review and implementation complete	6

D. HEDs to be corrected by the end of the first refueling outage

1.	Open pending implementation of correction	4
2.	Open pending additional review, revised response, and implementation of correction	1

E. HEDs for which acceptable justification for not correcting has been, or is expected to be, provided

1.	Closed	12
2.	To be closed on revised response	5

The staff found proposed HED corrections, implementation schedules, and justifications to be generally acceptable. However, as indicated above, the staff was concerned about the disposition of some HEDs (those requiring additional review and/or revised response). Concerns were discussed with the applicant during the preimplementation audits. Comments related to HEDs about which the staff has concerns are provided in Appendix C of the TER (the comment portion of Appendix C to the TER has not been superseded).

The staff was also concerned about the auditability of the resolution process for procedure-related observations that were a DCRDR product and that were sent to the the applicant's Operations Section for resolution. On the basis of discussion during the preimplementation audit, the staff understands that an auditable record of the disposition of those HEDs will be maintained. The applicant should use that record as a tool to ensure all safety-significant concerns are resolved and that technically adequate PEIs are supported by the control room. A summary statement concerning the resolution of procedure-related observations should be provided for staff review.

As a result of the first preimplementation audit, the staff was concerned about progress in implementing HED corrections. The applicant made specific commitments for implementation of HED corrections in the Summary Report. Those commitments were confirmed by the applicant's July 25, 1985 letter (M. R. Edelman to B. J. Youngblood) and in discussions during the first preimplementation audit. Initial progress in correcting HEDs was slow despite those commitments and confirmations. A second preimplementation audit was therefore conducted in September 1985; the results of that audit have indicated that the pace of HED

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corrections has increased. The applicant's continuing attention to HED corrections is expected to satisfy its commitments in time for Perry Unit 1 licensing (Fall of 1985).

18.4 Conclusion

Several activities must be completed to close out the Perry Unit 1 DCRDR. Those activities are:

(1) Function and task analysis: Update the task analysis to reflect the final revision of the PEIs to be implemented before fuel load.

(2) Comparison of display and control requirements with a control room inventory: Compare the control room inventory with results of the task analysis update.

(3) Control room survey: Survey communications equipment and environmental conditions in the completed control room and remote shutdown panel.

(4) Assessment: Assess HEDs identified by comparison of the control room inventory with results of the updated task analysis and by the remaining control room survey activities.

(5) Selection of design improvements: Select design improvements for safety-significant HEDs identified by comparison of the control room inventory with results of the updated task analysis and by the remaining control room survey activities.

(6) Verification: Augment the existing verification processes in a way that will ensure that all proposed corrections work together to provide a consistent, coherent, and effective control room interface with the operator (include assessment of concerns identified in Appendix D of the TER and selection and verification of design improvements which resolve those concerns).

(7) Summary Report: Supplement the Summary Report to provide revised responses to HEDs identified in Appendix C of the TER and updated implementation status of HED corrections.

In addition to the above, the applicant has not satisfied prelicensing commitments for HED correction. In the staff's judgment, to satisfy prelicensing commitments and the DCRDR requirements in Supplement 1 to NUREG-0737, the above items must be completed. Evaluation of the Perry Unit 1 DCRDR will continue through completion of the above activities. In addition, satisfaction of the applicant's prelicensing commitments for HED corrections should be a key issue for licensing Perry Unit 1.

(1) Indicate the version of the BWR Owners Group EPGs upon which finalized PEIs are based.

(2) Provide results of the communications survey and of the interim and final environmental surveys.

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(3) Describe means used to augment the process for verification that selected improvements provide necessary correction without introducing new HEDs.

(4) Provide a summary statement concerning resolution of procedure-related observations identified by the DCRDR.

(5) Provide responses to previously identified HEDs as identified in Table 18.1.

(6) Provide proposals for correcting HEDs identified by the ongoing DCRDR activities listed above.

(7) Provide schedules for implementing proposed corrections to HEDs identified by the ongoing DCRDR activities.

(8) Provide justification for not correcting or partially correcting safety-significant HEDs identified by the ongoing DCRDR activities.

The following license condition should be incorporated in the operating license for Perry Unit 1 subject to further completion of the DCRDR activities:

(1) Before exceeding 5% of thermal rated power, the licensee shall:

(a) submit the results of a human factors survey of communications equipment in the Perry Unit 1 control room and remote shutdown panel

(b) submit the results of interim environmental surveys of the Perry Unit 1 control room and remote shutdown panel

(c) provide commitments to correct HEDs identified in completing the DCRDR (including implementation schedules)

(d) provide justification for decisions reached not to correct or to partially correct safety-significant HEDs identified in completing the DCRDR

(2) Before startup for the second cycle of operation, the licensee shall:

(a) implement HED corrections committed to in the January 10, 1985 Summary Report

(b) provide the results of final environmental surveys of the Perry Unit 1 control room and remote shutdown panel

This condition is being added in Section 1.11 of this supplement as License Condition (30).

18.5 TMI Action Plan Item II.K.3.27

TMI Action Plan Item II.K.3.27 requires that a common reference level be provided for vessel level instrumentation. In the DCRDR Summary Report for the Perry Nuclear Power Plant, dated January 10, 1985, the applicant committed to establish a common reference level for vessel level instrumentation. The applicant made its commitment in response to HED No. 79. That HED and the applicant's response read as follows:

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- HED No. 79 - Different zero references are used for reactor water level instruments. This may complete comparing readings from multiple indications.

- Response - All the vessel level indications will be referenced to the top of active fuel.
- Schedule - Complete by Perry Unit 1 fuel load.

Establishment of the common reference level before Perry licensing (i.e., by fuel load time) will satisfy the requirement of TMI Action Plan Item II.K.3.27.

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Table 18.1 Status of human engineering discrepancy (HED) corrections based on April 8-12, 1985 preimplementation audit

HED status	HED no.
Corrected and closed	6, 17, 18, 19, 21, 28, 30, 35, 39, 44, 45, 46, 47, 48, 99, 118, 121, 149, 186, 187, 190, 191, 367, 1008, 1016
To be corrected by fuel load	
Open pending implementation of correction	1, 3, 4, 5, 7, 8, 9, 10, 12, 13, 15, 16, 22, 25, 31, 33, 34, 37, 38, 40, 41, 42, 43, 49, 50, 51, 52, 53, 55, 56, 57, 59, 60, 61,* 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 73, 75, 78, 79, 82, 83, 87, 89, 90, 91, 92, 93, 94, 95, 98, 101, 103, 105, 106, 109, 110, 111, 112, 113, 114, 115, 116, 117, 119, 120, 122, 123, 124, 125, 126, 127, 129, 130, 131, 132, 133, 134, 136, 137, 139, 140, 141, 142 143, 144, 145, 146, 147, 148, 150, 151, 152, 153, 154, 155, 156, 157, 158, 159, 160, 161, 162, 163, 164, 165, 166, 167, 168, 170, 171, 172, 173, 174, 175, 176, 177, 178, 181, 182, 184, 189, 193, 194, 195, 196, 197, 198, 200, 201, 202, 203, 204, 205, 208, 209, 210,** 211, 212, 213, 214, 215, 216, 301, 303, 304, 305, 306 307, 308, 309, 310, 311, 312, 319, 320, 321, 322, 323, 324, 325, 326, 327, 329, 330, 331, 332, 333, 334, 335, 336, 337, 338, 339, 340, 341, 342, 344, 345, 346, 347, 348, 349, 350, 353, 355, 356, 358, 359, 361, 362, 365, 371, 400, 402, 403, 404, 405, 406, 407, 1001, 1002, 1003, 1004, 1005, 1007, 1010, 1011, 1013, 1014, 1015, 1017, 1018, 1020, 1022, 1023, 1024, 1025, 1026, 1027, 1028, 1029, 1030, 1031, 1033, 1034, 1035, 1036, 1037
Open pending additional review, revised response, and implementation of correction	2, 14, 23, 29, 32, 36, 54, 76, 85, 86, 96, 104, 128, 135, 138, 169, 179, 180, 183, 185, 188, 199, 302, 318, 343, 351, 357, 366, 368, 401, 1006, 1009, 1012, 1021, 1032

See footnotes at end of table.

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Table 18.1 (Continued)

HED status	HED no.
Partial or interim corrections will be implemented by licensing; will be completely corrected by end of first refueling outage.	
Open pending implementation of partial or interim corrections	84, 102, 314, 328, 360, 363, 364, 369, 370
Open pending additional review, revised response, and implementation of partial or interim correction	77, 80, 81, 100, 313
To be corrected by end of first refueling outage	
Open pending implementation of correction	72, 74, 107, 408
Open pending additional review, revised response, and implementation of corrections	354
Acceptable justification for not correcting has been, or is expected to be, provided	
Closed	11, 20, 24, 27, 58, 97, 108, 192, 206, 207, 300, 315, 316
To be closed on revised response	26, 88, 317, 352, 1019

*Revised response/justification is necessary if CEI chooses not to expand water level range indication at the remote shutdown panel to include the top of the vessel.

**No implementation schedule is provided; prelicensing completion is consistent with schedules for correction of other HEDs.

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APPENDIX A

CONTINUATION OF CHRONOLOGY
PERRY NUCLEAR POWER PLANT, UNITS 1 AND 2

March 25, 1985	Letter from applicant updating response to Question 630.12 reflecting current plans in the matter of fire brigade staffing and training (SER Section 13.1.2.5).
March 26, 1985	Letter from applicant providing additional clarification regarding purge system and related operating guidelines for purge system operating cycles--SER Confirmatory Issue (56) and License Condition (24).
March 26, 1985	Letter from applicant requesting revision to SER to address use of GE postirradiation surveillance program for Perry.
March 27, 1985	Letter from applicant updating the Perry site organization to include established site protection section in the plant organization.
April 2, 1985	Letter from applicant submitting FSAR Technical Specification related changes to be documented in FSAR Amendment 18.
April 2, 1985	Letter from applicant submitting clarification of Perry's conformance to regulatory guides.
April 3, 1985	Letter from applicant submitting NRC requested environmental qualification files for three items of mechanical equipment--SSER No. 5 Outstanding Issue (4).
April 3, 1985	Letter from applicant providing additional information relative to suppression pool temperature limits--SER Confirmatory Issue (21).
April 4, 1985	Letter from applicant submitting revised Preservice Inspection Program which includes RCIC feedwater system, and LPCS--SER Confirmatory Issue (15).
April 8, 1985	NRC letter submitting "Proof and Review" copy of Perry Unit 1 Technical Specifications.
April 8, 1985	Letter from applicant requesting partial exemption to the airlock full-pressure test requirement of Paragraph III.D.2(b)(ii) of Appendix J to 10 CFR 50.
April 8, 1985	NRC letter requesting additional information related to the Humphrey containment design issue concerns as they related to Perry--SER Outstanding Issue (8).

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April 10, 1985	Letter from applicant submitting FSAR Amendment 18.
April 12, 1985	NRC letter issuing advance copies of Perry SER Supplement No. 6.
April 15, 1985	NRC letter requesting additional information with respect to Perry compliance with NRC Generic Letter 83-28, Items 1.1 and 2.1.
April 15, 1985	NRC letter submitting staff's evaluation report resolving Perry's conformance with containment purge and vent valve operability provisions of TMI Action Plan Item II.E.4.2(f)--SER Confirmatory Issue (23).
April 15, 1985	NRC letter submitting staff's/staff consultant's evaluation report resolving Perry's conformance with TMI Action Plan Item II.D.1--SER Confirmatory Issue (7).
April 16, 1985	NRC letter transmitting fire protection site audit report from March 18-21, 1985 audit.
April 18, 1985	NRC letter deleting as a Technical Specification shoreline erosion monitoring.
April 19, 1985	NRC letter transmitting 20 printed copies of Perry SER Supplement No. 6.
April 19, 1985	Letter from applicant responding to questions transmitted with NRC letter dated March 19, 1985, relative to Perry Unit 1 Initial Test Program--SER Confirmatory Issue (62).
April 22, 1985	NRC letter confirming that all State and county official comments on evaluation time estimates are included in Perry Emergency Plans, Rev. 4--SER Confirmatory Issue (61).
April 22, 1985	Letter from applicant submitting Perry Licensed Operator Requalification Program.
April 24, 1985	NRC letter requesting further information on use of stiff pipe clamps in the Perry piping system (Q210.15).
April 25, 1985	Letter from applicant advising of delay in submission of Rev. 4 to the Perry Fire Protection Evaluation Report.
April 25, 1985	Letter from applicant requesting relief from performing 20 additional fast-start diesel generator tests.
April 25, 1985	Letter from applicant responding to staff question submitted by letter dated March 21, 1985 relative to the Perry safety parameter display system--SER Confirmatory Issue (57).
April 29, 1985	NRC letter advising of the acceptability of the Perry safety parameter display system subject to site confirmatory audit--SER Confirmatory Issue (57).

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April 29, 1985	Letter from applicant responding to questions submitted by letter dated February 21, 1985 relative to the Perry Initial Test Program--SER Confirmatory Issue (62).
April 29, 1985	Letter from applicant requesting use of ASME Code Case N-413 to minimize size of filled welds for linear type supports.
April 29, 1985	Letter from applicant responding to questions submitted by letter dated February 11, 1985, relative to changes in Section 17.2 of the FSAR--SER Confirmatory Issue (59).
May 2, 1985	Letter from applicant commenting on draft Environmental Protection Plan for Perry Unit 1 submitted by NRC letter dated March 13, 1985.
May 3, 1985	Letter from applicant responding to fire protection site audit (March 18, 1985) open item on penetration, BTP CMEB 9.5-1, Section C.5.a.(3).
May 8, 1985	Letter from applicant clarifying Perry SER Section 6.3.1.3 relative to SRV operability.
May 9, 1985	Letter from applicant responding to IE Bulletin 79-01--relative to SER Outstanding Issue (4).
May 9, 1985	Letter from applicant providing information relative to diesel generator override and dc undervoltage alarm--SER Confirmatory Issue (35)/License Condition (22).
May 13, 1985	NRC letter granting relief from 20 fast-start tests requested by applicant's letter dated April 25, 1985.
May 13, 1985	Letter from applicant submitting Perry FSAR Amendment 19.
May 14, 1985	Letter from applicant submitting additional clarification of Perry conformance with regulatory guides.
May 15, 1985	Letter from applicant submitting Revision 4 (Chapter 8) to the Safeguards Contingency Plan for Perry.
May 15, 1985	Letter from applicant addressing Agreement 1 and Issue 1 of the fire protection audit report submitted by NRC letter dated April 16, 1985.
May 16, 1985	Letter from applicant providing additional LOCA-related pool dynamic load information relative to topics discussed at the November 15, 1985 and February 12, 1985 meetings between the NRC staff and the applicant.
May 17, 1985	NRC letter deleting SER License Condition (2), measurement of fuel channel box deflections, and accepting the substitution of the General Electric postirradiation surveillance program requested by applicant's letter dated March 26, 1985.

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May 17, 1985	NRC letter granting authorization to use ASME Code Case N-413 for Perry requested by applicant's letter dated April 29, 1985.
May 17, 1985	NRC letter identifying need for clarification of changes made in Chapter 13 of the FSAR in FSAR Amendment 18.
May 20, 1985	NRC letter providing staff comments/questions on clarification of conformance with regulatory guides addressed in applicant's letter dated April 2, 1985.
May 20, 1985	NRC letter providing staff comments on the Offsite Dose Calculation Manual submitted by applicant's letter dated February 28, 1985.
May 21, 1985	Letter from applicant addressing remaining agreement and issues identified in the NRC fire protection audit report dated April 16, 1985.
May 22, 1985	Letter from applicant providing update of two of the three mechanical equipment environmental qualification files submitted initially by applicant's letter dated April 3, 1985--SER Outstanding Issue (4).
May 22, 1985	Letter from applicant submitting Emergency Plan (OM-15A), Appendix D (confirms evacuation time estimates from State agencies).
May 23, 1985	Letter from applicant confirming basis upon which the containment integrated leak rate test of the Initial Test Program is to be performed.
May 23, 1985	Letter from applicant submitting Revision 4 of the Perry Fire Protection Evaluation Report.
May 29, 1985	NRC letter identifying discrepancies in changes made to Chapter 7 (I&C) by FSAR Amendment 18.
May 29, 1985	Letter from applicant requesting delay in finalization of Technical Specifications for Perry Unit 1 to July 15, 1985.
May 29, 1985	Letter from applicant updating status of SER license conditions and requesting deletion of License Conditions (6), (9), and (16).
May 31, 1985	NRC letter submitting report of site visit (April 23-25, 1985) to verify installation of I&C system design, resolving SER Confirmatory Issues (28) and (31); identifies need for site audit of applicant's commitment to separate HPCS Div. 3 from ATWS Div. 3 cabling as new confirmatory issue.
June 3, 1985	Letter from applicant providing information on PSI/ISI Program items identified in SSER No. 5, Sections 5.2.5.2 and 6.5.3, for resolution of SER Confirmatory Issue (15).

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June 4, 1985	Letter from applicant requesting staff acceptance on use of ASME Code Case N-393, "Repair Welding Structural Steel Rolled Shapes and Plates for Component Supports."
June 7, 1985	Letter from applicant submitting final analysis of ASME Code Class 1 piping break locations and dynamic effects--SER Confirmatory Issue (1).
June 10, 1985	NRC letter accepting applicant's description of the containment integrated leak rate test with clarifications.
June 10, 1985	NCR letter requesting additional information to clarify changes reflected in FSAR Amendment 18, Section 5.2.5, relative to RCPB leak detection methods.
June 10, 1985	NRC letter advising of unacceptability of plant fire protection barrier penetration designs (sealing criteria proposed in applicant's letter of May 3, 1985).
July 11, 1985	Letter from applicant updating Perry Unit 1 construction/test progress, revising fuel load date to September 14, 1985.
June 12, 1985	Letter from applicant requesting additional deviations to 10 CFR 50, Appendix R, fire protection provisions.
June 14, 1985	Letter from applicant providing results of TDI diesel generator torsiograph and cylinder imbalance tests in partial response to SER Confirmatory Issue (63).
June 17, 1985	NRC letter requesting additional information relative to potential impact of 10 CFR 21 notification pertaining to TDI diesel generators.
June 17, 1985	NRC letter clarifying SRV operability (as stated in SER Section 6.3.1.3) per applicant's request of May 8, 1985.
June 18, 1985	Letter from applicant clarifying the qualifications of the Chairman and members of the Nuclear Safety Review Committee (SER Section 13.4.2 proposed change).
June 18, 1985	Letter from applicant addressing staff questions (NRC May 20, 1985 letter) relative to conformance with Regulatory Guides 1.52, 1.140, and 1.143.
June 18, 1985	Letter from applicant responding to staff questions (NRC May 17, 1985 letter) relative to changes to Chapter 13 of the FSAR.
June 19, 1985	NRC letter requesting applicant to transmit plant descriptive information and emergency preparedness plans, and future changes, to the Atomic Energy Control Board of Canada.

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June 21, 1985	Letter from applicant responding to staff questions on changes to Chapter 7 of the FSAR (NRC May 29, 1985 letter).
June 24, 1985	NRC letter requesting assistance in addressing concerns expressed by M. Hite during his limited appearance session before the Perry Hearing Board on April 11, 1985.
June 24, 1985	NRC letter indicating staff's acceptance for the use of ASME Code Case N-393 in Perry construction (applicant's request of June 4, 1985).
June 24, 1985	NRC letter requesting clarification of plant conformance with Regulatory Guide 1.68 (Position C.3 of RG 1.68.2).
June 24, 1985	Letter from applicant responding to NRC letter dated April 8, 1985 relative to SER Outstanding Issue (8), "Mark III Containment Systems (Humphrey Issues)."
June 25, 1985	NRC letter requesting additional information relative to Licensed Operator Requalification Program.
June 25, 1985	Letter from applicant advising of proposed schedule for meeting Hydrogen Control Rule requirements of 10 CFR 50.44(c)(3)(vii)(D).
June 26, 1985	NRC letter requesting additional information relative to air quality standard for service air system as changed in FSAR Amendments 17 and 18.
June 26, 1985	NRC letter providing rewrite of SER Section 17.2, closing all QA staff concerns through FSAR Amendment 19, including SER Confirmatory Issue (59).
June 26, 1985	NRC letter requesting applicant's commitment relative to Interim Guidance vs. Emergency Planning Standard 10 CFR 50.47(b)(12)--GUARD vs. NRC, 753 F.2d 1144 (D.C. cir. 1985).
June 26, 1985	Letter from applicant responding to staff alternative relative to fire protection BTP CMEB 9.5-1, Section C.5.1(3), penetrations (refer to NRC letter of June 10, 1985).
June 27, 1985	Letter from applicant submitting plan to perform Initial Test Program in expanded areas of the power/flow operating map currently included in FSAR (Maximum Extended Operating Domain).
June 27, 1985	Letter from applicant addressing staff's comments/questions relative to plant conformance with Regulatory Guides 1.39, 1.68.2 (Position C.3), 1.123, and 1.143--SER Confirmatory Issue (59).
June 28, 1985	Letter from applicant responding to staff questions relative to TDI diesel generator reliability--SER Confirmatory Issue (63).

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July 2, 1985	Letter from applicant responding to NRC letter of June 19, 1985 requesting plant information and emergency preparedness plans changes to the Atomic Energy Control Board of Canada on a routine basis.
July 2, 1985	Letter from applicant addressing TDI diesel generator Part 21 notifications requested by NRC letter dated June 21, 1985.
July 3, 1985	NRC letter correcting error in Sections 13.4.3 of the SER relative to the Independent Safety Engineering Group.
July 3, 1985	NRC letter revising Perry Unit 1 Technical Specification schedule consistent with fuel load date.
July 5, 1985	NRC letter advising the applicant of the staff's acceptance of the Initial Test Program as documented in the FSAR through FSAR Amendment 17--SER Confirmatory Issue (62).
July 5, 1985	NRC letter requesting confirmatory information relative to performance of surveillance testing pertaining to RG 1.118, Rev. 2, "Periodic Testing of Electrical Power and Protection Systems."
July 8, 1985	Letter from applicant addressing Q210.09 items contained in NRC letter of December 14, 1984 (SRV piping and support analysis).
July 8, 1985	NRC letter deleting SER License Condition (6), "IE Bulletin 80-06 ESF Reset Control."
July 9, 1985	Letter from applicant proposing deletion of SER License Condition (9) relative to HPCS diesel generator wear test data.
July 11, 1985	NRC letter requesting further information/clarification of Perry's conformance with RGs 1.52, 1.140, and 1.143 additional to that provided in applicant's letter dated June 18, 1985.
July 11, 1985	Letter from applicant providing Perry Unit 1 progress update.
July 15, 1985	NRC letter requesting additional information pertaining to the final analyses of ASME Code Class 1 pipe break locations and dynamic effects--SER Confirmatory Issue (1).
July 17, 1985	Letter from applicant responding to NRC comments on the Offsite Dose Calculation Manual provided by NRC letter dated May 20, 1985.
July 17, 1985	Letter from applicant submitting preliminary report of pre-operational environmental radiation-monitoring data.

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July 18, 1985	Letter from applicant responding to NRC Q480.49-Q480.51 and containment bypass leakage concerns documented in NRC December 6, 1984 meeting reports--related to SER License Condition (16).
July 19, 1985	NRC letter accepting files provided relevant to environmental qualification of mechanical equipment installed in plant--SER Outstanding Issue (4a).
July 19, 1985	Letter from applicant providing information requested by NRC letter of June 24, 1985 relative to concerns expressed by Milton Hite on landfill located 3 miles from the Perry plant site.
July 19, 1985	Letter from applicant submitting FSAR Amendment 20.
July 22, 1985	NRC letter defining post-100-hour inspections and tests of the TDI diesel generators.
July 24, 1985	Letter from applicant responding to the NRC staff's comments on RGs 1.52, 1.140, and 1.143 (NRC letter dated July 11, 1985).
July 26, 1985	Letter from applicant clarifying main steam isolation valve leakage testing per 10 CFR 50, Appendix J (Technical Specifications Section 3/4.6.1.2).
July 26, 1985	NRC letter deleting SER License Condition (9) relative to the HPCS diesel generator cold start wear tests.
July 30, 1985	Letter from applicant qualifying his response to NRC staff question Q420.03 relative to control system failures--SER Outstanding Issue (14).
July 31, 1985	NRC letter indicating that SER Confirmatory Issue (56), regarding containment purge programs required in Section 6.2.4 of SSER No. 4 has been resolved to the staff's satisfaction.
July 31, 1985	Letter from applicant clarifying "operator at the controls" per RG 1.114.
August 1, 1985	Letter from applicant providing test results relative to fire protection penetration seals within conduit (update of information provided by the applicant's letters dated May 3, 1985 and June 26, 1985, same subject).
August 1, 1985	Letter from applicant submitting the Perry Process Control Program for radwaste solidification required by the Technical Specifications and 10 CFR 50.34a.
August 5, 1985	NRC letter advising the applicant of the revised physical security plan license condition to be addressed in Perry Unit 1 operating license (supersedes condition stated in Section 1.11 of SSER No. 6).

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August 6, 1985	Letter from applicant submitting Revision 5 of the Perry Emergency Plan, OM-15A.
August 7, 1985	Letter from applicant updating prior submittals regarding the Perry Preservice Inspection Program--SER Confirmatory Issue (15).
August 8, 1985	Letter from applicant clarifying CEI's position with respect to the testing and inspection to be performed on TDI diesel generators following 100-hour preoperational tests--portion of SER Confirmatory Issue (63).
August 8, 1985	Letter from applicant providing additional information concerning changes made in the FSAR relative to instrument air quality (response to NRC letter dated June 26, 1985).
August 8, 1985	NRC letter requesting further information on CEI's conformance with RGs 1.52, 1.140, and 1.143.
August 9, 1985	Letter from applicant providing proposed FSAR and Technical Specification revisions associated with the fracture toughness of the reactor coolant pressure boundary materials--SER Confirmatory Issue (17).
August 14, 1985	Letter from applicant identifying the basis for the changes and clarifications made to Chapter 12 of the FSAR in FSAR Amendment 20.
August 14, 1985	NRC letter requesting further clarification of the Process Control Program and related radwaste solidification system to be utilized in the Perry plant.
August 15, 1985	Letter from applicant updating Perry Unit 1 licensing progress.
August 15, 1985	Letter from applicant submitting Revision 1 to the Offsite Dose Calculation Manual for Perry Unit 1.
August 19, 1985	NRC letter directing the applicant's attention to Generic Letter 85-15 alerting all licensees to the November 30, 1985 deadline for compliance with the "EQ" Rule, 10 CFR 50.49.
August 20, 1985	NRC letter requesting additional information relative to Perry's conformance with RG 1.114.
August 20, 1985	NRC letter advising applicant of acceptability of fire brigade staffing and training qualifications in response to NRC Question 630.12.
August 20, 1985	Letter from applicant submitting changes to the Perry system vibration and thermal expansion test program.

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August 20, 1985	Letter from applicant providing additional information regarding Perry's conformance with RG 1.118 (response to NRC letter dated July 5, 1985).
August 20, 1985	Letter from applicant submitting proposed addition to the Perry Security Plan.
August 21, 1985	Letter from applicant describing operating shift experience in response to License Condition (10) in Section 1.11 of SSER No. 6 and Generic Letter 84-16.
August 21, 1985	Letter from applicant submitting Revision 1 to the Perry Pump and Valve Inservice Testing Program--pertains to SER License Condition (26).
August 22, 1985	Letter from applicant providing additional information re the Perry Licensed Operator Requalification Program (response to NRC letter dated June 25, 1985).
August 26, 1985	NRC letter requesting basis for change reflected in Table 3.2-1 of FSAR Amendment 20 regarding safety classification of the Plant Transverse Incore Probe and Subsystems.
August 26, 1985	NRC letter transmitting update on status of the Detailed Control Room Design Review--SER Outstanding Issue (7).
August 28, 1985	Letter from applicant relating status of equipment qualifications--SER Outstanding Issue (4).
August 28, 1985	Letter from applicant addressing Perry compliance with Sections 1.1 and 2.1 of Generic Letter 83-28, ATWS (response to NRC letter dated April 15, 1985).
August 29, 1985	Letter from applicant correcting proper classification of the Transverse Incore Probe and Subsystems (response to NRC letter dated August 26, 1985).
August 30, 1985	Letter from applicant providing information relative to Perry firewall configurations (response to site audit fire protection report submitted by NRC letter dated April 16, 1985).
August 30, 1985	Letter from applicant relative to feedwater isolation valve testing (response to NRC Question 480.50).
August 30, 1985	Letter from applicant updating response to NRC Question 430.11 relative to current fire protection emergency lighting design (response to NRC audit report dated April 16, 1985).
August 30, 1985	Letter from applicant advising of change in control room carpeting to be reflected in a future FSAR amendment.
August 30, 1985	Letter from applicant providing information relative to switchgear room fire-fighting flooding/drainage (NRC audit report dated April 16, 1985).

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August 30, 1985	Letter from applicant providing information requested by NRC letters dated August 8 and August 14, 1985 regarding Perry conformance to RGs 1.52, 1.140, and 1.143; and the Process Control Program for Radwaste Solidification.
September 3, 1985	NRC letter accepting changes made to Chapter 12 of the FSAR reflected in FSAR Amendment 20.
September 3, 1985	Letter from applicant providing additional information requested on Perry's conformance with RG 1.114 (response to NRC letter dated August 20, 1985).
September 3, 1985	Letter from applicant submitting copy of contract executed with the U.S. Department of Energy for the disposal of nuclear waste--SER License Condition (20).
September 5, 1985	Letter from applicant identifying proposed FSAR Appendix 1B "license commitments" from Section 1.11 of the SER and supplements through SSER No. 6 to be incorporated in a future FSAR amendment.
September 5, 1985	Letter from applicant responding to request for additional information relevant to ASME Code Class 1 pipe break locations and dynamic effects-feedwater line (response to NRC letter dated July 15, 1985).
September 6, 1985	Letter from applicant providing information clarifying the implementation of equipment in conformance with TMI Action Plan Items II.B.3, II.F.1.1, and II.F.1.2 pertaining to postaccident sampling, noble gas effluent monitors, and accident range iodine and particulate sampling respectively.
September 9, 1985	NRC letter advising applicant of need to consider other systems in complying with the provisions of TMI Action Plan Item III.D.1.1--SER License Condition (16).
September 11, 1985	Letter from applicant submitting Procedures Generation Package per TMI Action Plan Item I.C.1--SER Outstanding Issue (21).
September 11,1985	Letter from applicant providing verification of information relative to reactor coolant pressure boundary leak detection system (supplementing information provided in letter dated July 22, 1985).
September 12, 1985	Letter from applicant requesting deletion of simulated loss of ac power tests per Generic Letter 83-24.
September 12, 1985	Letter from applicant withdrawing a previous Appendix A deviation request (Fire Area STW638/654) and providing information pertaining to bullet-resistant walls and fire door labeling.

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September 13, 1985	Letter from applicant providing clarification of the applicant's May 16, 1985 letter pertaining to the resolution of the pool dynamic loads--SER Outstanding Issue (9).
September 17, 1985	NRC letter acknowledging the incorrect classification of the Transverse Incore Probe in Table 3.2-1 of FSAR Amendment 20.
September 17, 1985	Letter from applicant clarifying information contained in FSAR Chapter 13 relative to plant organization.
September 17, 1985	Letter from applicant addressing storage capacity to accommodate design-basis flooding volumes due to potential circulating water system expansion joint failure in the turbine building--SER Confirmatory Issue (54).
September 18, 1985	NRC letter requesting the applicant's permission to reprint copyrighted material on the Process Control Program for Radwaste Solidification provided by applicant's letter dated August 30, 1985.
September 18, 1985	NRC letter requesting applicant's permission to reprint copyrighted material submitted by letter dated August 30, 1985 regarding Process Control Program for Radwaste Solidification.
September 18, 1985	Letter from applicant proposing deletion of MSIV leakage control system testing in the initial startup program.
September 19, 1985	Letter from applicant updating Perry Unit 1 operational readiness for licensing.
September 19, 1985	Letter from applicant submitting information supplemental to that in CEI's July 17, 1985 letter pertaining to the offsite dose calculation manual.
September 20, 1985	Letter from applicant providing additional information regarding feedwater isolation valve testing (related to staff question Q480.50).
September 20, 1985	NRC letter advising of staff's acceptability of schedule for meeting the requirements of the hydrogen control rule.
September 23, 1985	Letter from applicant updating letter dated August 28, 1985 providing procedure details of Perry post-trip review program in response to NRC Generic Letter 83-28 relative to anticipated transient without scram (ATWS).
September 23, 1985	Letter from applicant providing further information regarding pool dynamic loads--SER Outstanding Issue (9).
September 23, 1985	Letter from applicant providing final update of status of equipment qualification--SER Outstanding Issue (4).

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September 24, 1985	NRC letter advising applicant of required schedule for implementation of hydrogen control equipment enhancement in the Perry plant--10 CFR 50.44(3)(c)(vii)(A).
September 24, 1985	Letter from applicant providing additional clarifications relative to Mark III (Humphrey) containment system issues--SER Outstanding Issue (8).
September 24, 1985	Letter from applicant commenting on proposed compliance with TMI Action Plan Item III.D.1.1.
September 26, 1985	Letter from applicant providing information relative to control room panel/cabinet fire detection.
September 27, 1985	Letter from applicant endorsing for Perry the NRC staff generic acceptability of LRG II resolution of Generic Issue 9-RSB, "Long-Term Operability of Deep Draft Pumps."
September 27, 1985	Letter from applicant submitting Revision 3 of the Perry Security Force Training and Qualification Plan.
September 30, 1985	Letter from applicant providing additional clarification addressing NRC staff concerns regarding CEI's program for performing reviews required by 10 CFR 50.59 and Perry draft Technical Specifications.
September 30, 1985	Letter from applicant further clarifying the Perry Licensed Operator Requalification Program dated June 25, 1985.
October 2, 1985	Letter from applicant providing schedule for completion of the Detailed Control Room Design Review items identified during the NRC staff site visit on September 10-13, 1985.
October 3, 1985	Letter from applicant relative to proposed deviation from 10 CFR 50, Appendix R on control room emergency lighting.
October 4, 1985	Letter from applicant submitting Revision 5 to the Perry Security Plan.
October 4, 1985	Letter from applicant identifying change in the classification of the traversing incore probe in FSAR Table 3.2-1.
October 4, 1985	Letter from applicant requesting delay in submittal of the Perry Final Technical Specifications.
October 4, 1985	Letter from applicant submitting FSAR Amendment 21.
October 8, 1985	Letter from applicant providing further confirmatory information relative to SER Outstanding Issues (8) and (9).
October 9, 1985	Letter from applicant providing information on Technical Specification Table 3.6.4-1 (valves which are water tested

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	and valves which are air tested) and Surveillance Technical Specification 4.6.2.3.b relevant to drywell airlock pressure testing.
October 14, 1985	Letter from applicant submitting Supplement 1 to the Perry Detailed Control Room Design Review Summary Report--SER Outstanding Issue (7).
October 17, 1985	Letter from applicant requesting exemption from 10 CFR 50, Appendix E, Section IV.F.1 regarding full-participation emergency preparedness exercise.
October 17, 1985	Letter from applicant describing methodology used to establish instrumentation setpoints and allowable values for the reactor protection system and engineered feature trip function.
October 21, 1985	NRC letter transmitting final draft of the Perry Unit 1 Technical Specifications for CEI comment.
October 21, 1985	Letter from applicant providing information on scheduling of operator licensing examination request by NRC Generic Letter 85-18.

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APPENDIX B

REFERENCES*

Cleveland Electric Illuminating Company, "Final Safety Analysis Report for the Perry Nuclear Power Plant, Units 1 and 2" (Docket Nos. 50-440 and 50-441), through Amendment 20, July 1985.

Code of Federal Regulations, Title 10, "Energy" (10 CFR), includes General Design Criteria (GDC).

General Electric Company, Letter SIL-380, "BWR Core Thermal-Hydraulic Stability," Rev. 1, Feb. 10, 1985.

---, Letter MFN-29-85, from H. C. Pfefferlen (GE) to C. O. Thomas (NRC) dated Feb. 28, 1985, Subject: "Power Generation Control Complex Fire Suppression Licensing Topical Report," Addendum 1.

---, Letter MFN-58-85, from R. Villa (GE) to C. O. Thomas (NRC) dated May 1, 1985, Subject: "Power Generation Control Complex Fire Suppression Licensing Topical Report," Addendum 1, Supplemental Information.

---, Licensing Topical Report NEDO-10466-A, "Power Generation Control Complex Design Criteria and Safety Evaluation," 1979.

---, Report 22A4365, "Interim Containment Loads," Apr. 1978.

---, Report SLI-8211, "Review of Reactor Water Level Measurement Systems," July 1982.

---, Report SLI-8218, "Inadequate Core Cooling Detection in BWRs," Dec. 1982.

---, Topical Report NEDE-13426-P, "Mark III Confirmatory Test Program. One-Third Scale Pool Swell Impact Tests, Test Series 5805," Aug. 1975.

---, Topical Report NEDE-22203-P, "Reactor Internals Vibration Predictions," Aug. 1982, Proprietary information, not publicly available.

---, Topical Report NEDE-24988-P, "Analysis of Generic BWR Safety/Relief Valve Operability Test Results," Oct. 1981, Proprietary information, not publicly available.

*All correspondence between the applicant and the NRC staff referenced in this supplement is listed in Appendix A of the SER and its supplements on a continuing basis.

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License Review Group (LRG) II, letter from D. L. Holtzscher (LRG II Chairman) to H. J. Faulkner (NRC), dated May 12, 1982, Subject: "Submittal of Position Papers for Licensing Review Group II Issues."

---, letter from D. L. Holtzscher (LRG II Chairman) to J. J. Stefano (NRC), dated Sept. 19, 1983, Subject: "Submittal of Position Papers for Licensing Review Group II Issues."

Maise, G., "Suggested Acceptance Criteria for Impact Loads on Short Mark III Structures Close to the Pool," Department of Nuclear Energy, Brookhaven National Laboratory, Upton, N.Y. 11973, Feb. 15, 1984.

U.S. Nuclear Regulatory Commission, Generic Letter 82-33, D. G. Eisenhut to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits, "Supplement No. 1, NUREG-0737--Requirements for Emergency Response Capability," Dec. 17, 1982.

---, Generic Letter 83-18, "NRC Staff Review of BWR Owners Group Control Room Survey Program," Apr. 19, 1983.

---, Generic Letter 83-24, "Special Low Power Testing and Training, Recommendations for BWRs" (TMI Task Action Plan Item I.G.1, June 23, 1983.

---, IE Bulletin 79-27, "Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation," Nov. 30, 1979.

---, IE Bulletin 80-06, "Engineered Safety Feature (ESF) Reset Controls," Mar. 3, 1980.

---, letter from T. P. Speis to H. Pfefferlen (GE), dated October 8, 1982, Subject: "Draft Acceptance Criteria for LOCA Related Mark III Containment Pool Dynamic Loads," Appendix C of Attachment"

---, letter from B. J. Youngblood to D. L. Holtzscher (LRG II Chairman), dated July 16, 1985, Subject: "Acceptability of LRG II Position on Issue 9-RSB, Long-Term Operability of Deep Draft Pumps."

---, memorandum from S. Weiss to C. Thomas, dated Nov. 2, 1984, Subject: "Design Verification Audit Report for the General Electric Safety Parameter Display System.'

---, memorandum from V. Moore to A. Schwencer, dated Nov. 2, 1982, Subject: "Human Factors Engineering In-progress Audit Report, Perry Nuclear Power Plant Unit 1."

---, NUREG-75/110, Safety Evaluation Report for Preliminary Design Approval for GESSAR-238--Nuclear Island Standard Design," Dec. 1975.

---, NUREG-0487, "Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria," Oct. 1978.

---, NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Feb. 1980; Rev. 1, Nov. 1980.

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---, NUREG-0661, "Safety Evaluation Report for the Mark I Containment Long-Term Program," July 1980; Suppl. 1, Aug. 1982.

---, NUREG-0737, "Clarification of TMI Action Plan Requirements," Nov. 1980.

---, NUREG-0737, Supplement 1, see U.S. Nuclear Regulatory Commission, Generic Letter 82-33.

---, NUREG-0797, "Safety Evaluation Report Related to the Final Design of the General Electric Company BWR/6 Nuclear Island Design, GESSAR II," Supplement A, July 1985.

---, NUREG-0800 (formerly NUREG-75/087), "Standard Review Plan for Review of Safety Analysis Reports for Nuclear Power Plants," Rev. 2, July 1981 (includes Branch Technical Positions).

---, NUREG-0887, "Safety Evaluation Report Related to the Operation of the Perry Nuclear Power Plant, Units 1 and 2," May 1982; Supp. 1, Aug. 1982; Supp. 2, Jan. 1983; Supp. 3, Apr. 1983; Supp. 4, Feb. 1984; Supp. 5, Feb. 1985; Supp. 6, Apr. 1985.

---, NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition," Aug. 1984.

U.S. Nuclear Regulatory Commission Region III, Inspection Reports 50-440/85-009 and 50-441/85-007, "Emergency Preparedness Appraisal," May 1, 1985.

---, Inspection Report 50-440/850055, Aug 30, 1985.

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APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANTS

NRC STAFF

Name	Title	Branch
G. Bagchi	Section Leader, Seismic/Dynamic Loads	Equipment Qualifications
R. Becker	Sr. Nuclear Systems Engineer	Procedures and Systems Review
C. Berlinger	Lead Engineer	TDI/Diesel Generator Task Group
F. Eltawila	Sr. Containment Systems Engineer	Containment Systems
J. Fairobent	Meteorologist	Meteorology and Effluent Treatment
R. Giardina	Reactor Systems Engineer, Mechanical	Power Systems
R. Gonzales	Hydraulic Engineer	Environmental and Hydrologic Engineering
P. Hearn	Mechanical Engineer (Auxiliary Systems)	Auxiliary Systems
M. Hum	Materials Engineer	Materials Engineering
J. Joyce	Sr. Reactor Engineer (Instrumentation)	Instrumentation and Control Systems
G. Lapinski	Engineering Psychologist	Human Factors Engineering
R. Manili	Plant Protection Analyst	Power Reactor Safeguards*
J. Mauck	Reactor Engineer (Instrumentation)	Instrumentation and Control Systems
P. McLaughlin	Organization and Management Specialist	Licensee Qualification

*Office of Nuclear Materials Safety and Safeguards

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NRC STAFF (Continued)

Name	Title	Branch
A. Notafrancesco	Containment Systems Engineer	Containment Systems
D. Perrotti	Emergency Preparedness Engineer	Emergency Preparedness*
D. Persinko	Project Manager	TDI/Diesel Generator Task Group
J. Raval	Mechanical Engineer (Auxiliary Systems)	Auxiliary Systems
S. Rhow	Electrical Engineer (Reactor Systems)	Power Systems
C. Scheibelhut	Inspector	Region III
D. Serig	Human Factors Engineer	Human Factors Engineering
G. Stahley	Hydraulic Engineer	Environmental and Hydraulic Engineering
D. Terao	Mechanical Engineer	Mechanical Engineering
H. Walker	Mechanical Engineer	Equipment Qualifications
S. West	Fire Protection Engineer	Chemical Engineering
J. Wing	Senior Chemical Engineer	Chemical Engineering
R. Wright	Senior Equipment Qualification Engineer	Equipment Qualifications
S. Wu	Reactor Fuels Engineer	Core Performance

NRC CONSULTANTS

Name	Laboratory
K. Harmon	Lawrence Livermore National Laboratory
C. Kido	Idaho National Engineering Laboratory/EG&G
J. Moore	Lawrence Livermore National Laboratory
J. Savage	Lawrence Livermore National Laboratory

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APPENDIX G

ERRATA TO THE SAFETY EVALUATION REPORT AND SUPPLEMENTAL REPORTS

Section	Page	Change
1.11(SSER 6)	1-12	Item (18): Delete last sentence and substitute: "This condition was deleted in SSER No. 5."
9.1.1(SER)	9-2	Fourth complete paragraph, line 7: Delete "solid watertight covers" and substitute "a four-piece cover".
9.2.1(SER)	9-11	Third paragraph, line 7: After "heat exchangers," add "fuel pool cooling heat exchangers,". In line 11, after "traveling screens," add "standby liquid control transfer tank, fire protection systems hose stations in the vicinity of safe shutdown equipment,".
Table 9.2(SSER 4)	9-11	Eighth entry in the table: Change "1CC-4a, Division 1 Cable Spreading Room" to "1CC-4d, Division 2 Battery Room".
9.2.1(SER)	9-12	First paragraph, at the end of the second sentence: Add "and fuel pool cooling heat exchangers." Also at beginning of fourth line delete "and".
9.2.2(SER)	9-13	Third paragraph, to line 7: Change "40-day" to "7-day".
9.2.2(SER)	9-14	Third complete paragraph, line 8: After "drywell" add "equipment drain".
9.2.5(SER)	9-18	First full paragraph, line 2: Change "70,630 gpm" to "70,500 gpm".
9.4.1(SER)	9-27	Fifth complete paragraph, lines 2-3: Delete "all operating modes including LOCA conditions" and substitute "normal plant operation and plant shutdown".

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Section	Page	Change
9.5.1.4.4(SER)	9-40	Last sentence of third paragraph: Change "carbon monoxide" to "carbon dioxide". Fourth paragraph: Delete "and is separated from such areas by 3-hour-rated fire walls:".
9.5.1.5.1(SER)	9-42	Third paragraph, line 4: Change "valve, damper," to "valve tamper,".
9.5.1.5.2(SER)	9-43	First paragraph, line 4: Change "125 psig" to "141 psig".
9.5.1.6.1(SER)	9-46	First paragraph, lines 3 and 4: Change "ionization smoke detectors, and local application, carbon dioxide, extinguishing" to "heat detectors, ionization smoke detectors, and local application carbon dioxide extinguishing".
9.5.1.6.3(SER)	9-47	Third paragraph, line 6: Delete the word "automatically".
13.4.3(SER)	13-18	First paragraph, line 4: Delete "4.2" and substitute "4.7".

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APPENDIX N

DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY FOR THE PERRY NUCLEAR POWER PLANT UNITS 1 AND 2

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PERRY NUCLEAR POWER PLANT
UNITS 1 AND 2
DOCKET NUMBERS 50-440 AND 50-441

DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

C. Kido

Published March 1985

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Prepared for the
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Washington, D.C. 20555
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ABSTRACT

The containment purge and vent valve qualification program for the Perry Nuclear Power Plant has been reviewed by the NRC Licensing Support Section. The review indicates that the licensee has demonstrated the ability of the 18 in. and 42 in. valves to close against the buildup of containment pressure in the event of a DBA LOCA, with the condition that the 42 in. valves be limited to a 50° opening angle.

FOREWORD

This report is supplied as part of the "Equipment Qualification Case Reviews" project that is being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Engineering, Equipment Qualification Branch by EG&G Idaho, Inc., Engineering Analysis Division, NRC Licensing Support Section.

The U.S. Nuclear Regulatory Commission funded this work under the authorization, B&R 20-19-40-41-2, FIN Number A6415.

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SUMMARY

The Perry containment purge and vent valve qualification program has been reviewed by the NRC licensing support section of EG&G Idaho, Inc., who provide technical assistance to the NRC Equipment Qualification Branch (EQB). Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design basis accident, is necessary to assure containment isolation. This demonstration of operability is required by Standard Review Plant (SRP) 6.2.4, Branch Technical Position (BTP) CSB 6-4, and SRP 3.10 for containment purge and vent valves which are not sealed closed during operational conditions 1, 2, 3, and 4.

Material contained in the Perry Final Safety Analysis Report (FSAR) and purge valve qualification report formed the basis for this evaluation. Qualification of the valves was based on fluid dynamic analyses and on generic 5 in. model tests performed by the manufacturer using the worst case configuration and load combinations. In summary, we find that the information submitted demonstrated the ability of the 18 in. and 42 in. valv to close against the buildup of containment pressure in the event of a DBA LOCA, with the condition that the 42 in. valves be limited to a 50° opening angle.

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PERRY NUCLEAR POWER PLANT

UNITS 1 AND 2

DOCKET NUMBERS 50-440 AND 50-441

DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

1. REQUIREMENT

Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design basis accident, is necessary to assure containment isolation. This demonstration of operability is required by Standard Review Plan (SRP) 6.2.4, Branch Technical Position (BTP) CSB 6-4, and SRP 3.10 for containment purge and vent valves which are not sealed closed during operational conditions 1, 2, 3, and 4.

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2. DESCRIPTION OF CONTAINMENT PURGE AND VENT VALVES

The following valves are identified in the licensee submittal and Perry FSAR Table 6.2-32 as being part of the containment purge and vent system.

Valve Tag No.	Size (in.)	Use	Location
M14F040	42	Supply	Outside Containment
M14F045	42	Supply	Inside Containment
M14F190	18	Supply	Inside Containment
M14F090	42	Exhaust	Outside Containment
M14F085	42	Exhaust	Inside Containment
M14F200	18	Exhaust	Inside Containment

The Pratt 18 in.-1200 butterfly valves are equipped with Bettis operators, Model T312B-SR2, air open-spring close, 47000 in.-lb maximum, 26000 in.-lb minimum rating. The Pratt 42 in.-1200 butterfly valves are equipped with Bettis operators, Model T420-SR2, air open-spring close, 100000 in.-lb maximum, 57400 in.-lb minimum rating. The full open position of the valve corresponds to a disc angle of 90°.

The containment purge and vent system for Perry will be operated at partial flow during normal plant operation and at full purge rate prior to personnel entry into the drywell and during refueling operation. During normal plant operation, the 42 in. valves located in the annulus will be open, while the 42 in. valves inside containment will be normally closed. A bypass line with an 18 in. normally open valve will serve as the normal purge pathway parallel to the normally closed 42 in. valve. This configuration will ensure that the net effective opening is limited to

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12 in., while allowing for the optimum air flow of 5000 cfm required to normally purge the plant. During the drywell purge mode (refueling and cold shutdown conditions), the inboard 42 in. isolation valves will be opened to permit a full purge rate of 30,000 cfm through the containment.

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3. DEMONSTRATION OF OPERABILITY

The following documents were submitted for review by the Cleveland Electric Illuminating Company to demonstrate operability of the Perry containment purge and vent valves.

1. Letter from M. A. Edelman, Vice President, Nuclear Group, Cleveland Electric Illuminating Company to B. J. Youngblood, Chief, Licensing Branch No. 1, Division of Licensing, U.S. Nuclear Regulatory Commission, Response to NUREG 0737, Item II.E.4.2(6), Letter No. PY-CEI/NRR-0154L, December 19, 1984.

2. Gilbert/Commonwealth Report, Isolation/Purge Valve Analysis for 18"-1200 Butterfly Valve, Specification No. SP-641-4549-00, Rev. XII, Pratt Job No. D-45608 (D-0086-10), September 21, 1983.

3. Gilbert/Commonwealth Report, Isolation/Purge Valve Analysis for 42"-1200 Butterfly Valve (Blocked at 50°), Specification No. SP-641-4549-00, Rev. XII, Pratt Job No. D-45608 (D-0086-1, -8), September 21, 1983.

The operability demonstration presented by the Henry Pratt Company in References 2 and 3 is based on the following considerations.

1. The valve closure time during a LOCA will be less than or equal to the no-flow time of 5 seconds, since fluid dynamic effects tend to assist valve closure.

2. The ability to isolate containment is challenged if either valve in series fails to close properly. Pratt has determined that the worst case configuration occurs if the outside containment valve is stuck fully open, requiring the inside valve to close against the full containment pressure. Although they have not conducted

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specific model tests with partially open upstream valves, Pratt believes that they would tend to lower closing torque requirements because of the pressure drop across the upstream valve.

3. The worst case configuration with respect to developed aerodynamic torque is a 90° elbow upstream oriented 90° out of plane with respect to the valve shaft, and leading edge of the disc closing toward the outer wall of the elbow. Furthermore, the maximum dynamic torque occurs when initial sonic flow is coincident with a disc angle of 72° (symmetric) or 68° (asymmetric). Alternate configurations were tested such as flow from the flat and arch side of the disc, clockwise and counterclockwise disc closure, and disc diameter to thickness ratios. The dynamic torques determined by 5 in. model tests were in all cases lower than those calculated by the Pratt purge valve analysis.

4. The Pratt purge valve analysis is based on the seismic loads (3 axes acting simultaneously) plus the LOCA-induced loads. The resulting combined stress is compared with ASME code criteria. The valve operator was evaluated by comparing the manufacturer's rating versus the calculated LOCA-induced fluid dynamic torques.

5. To determine the fluid dynamic torque of the 18 in. and 42 in. purge valves, Pratt applies sonic and subsonic torque coefficients as well as an empirical sizing factor to its torque equations. The torque coefficients and sizing factors are derived from analysis of experimental test data using a 5 in. test model and are correlated with analytically predicted behavior of airfoils in compressible media. The sizing factor for the 18 in. valve is 1.176 and is 1.220 for the 42 in. valve blocked at 50°.

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6. A constant upstream pressure of 26.7 psia was assumed for the torque calculations. This value envelopes the peak containment pressure that results from a double-ended guillotine break of the recirculation line. FSAR Figure 6.2-2 and Table 6.2-7 give the containment response as ~4.5 psig at 5 s, rising to a peak pressure of 11.31 psig after 11,128 s.

7. The Pratt valves supplied do not include accumulators or torque limiting devices, and are not affected by containment back pressure.

8. The molded EPT valve seats have a known cumulative radiation resistance of 10^8 rads at 350°F. In addition, the vendor recommends visual inspection every 18 months with replacement as needed, since the presence of debris or damage to the seats could impair sealing.

9. The calculation of torque values from full open to closed for the 18 in. valve and from 50° open to closed for the 42 in. valve are based on the specific purge valve analyses and on the generic 5 in. model tests conducted by the Henry Pratt Company using the worst case configuration and respective sizing factors as described above.

Based on the assumptions listed above, the highest resultant torque value for the 18 in. valve was 12200 in.-lb at a disc angle of 68° open. Since the minimum rating of the Bettis operator is 26000 in.-lb at 45°, the Gilbert report, Reference 2, concluded that the operator was structurally capable of withstanding the combined LOCA and seismic loads.

For the 42 in. valve, the Gilbert report, Reference 3, concluded that neither the valve structure nor the valve operator are adequate to withstand the combined LOCA and seismic loads except by restricting the valve opening to 50° or less. With the valve blocked at 50° the maximum required torque is 54700 in.-lb which is less than the minimum torque rating of the operator, 57400 in.-lb at 45°.

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Using the maximum calculated valve torque values, all components of each valve assembly were analyzed for stress with the added consideration that the valve is either at maximum fluid dynamic torque or seating against the maximum design pressure. Seismic accelerations of 3 g horizontal and 4 g vertical were applied simultaneously in all three orthogonal directions. The results of the 18 in. and 42 in. valve analyses are tabulated in Gilbert reports, References 2 and 3. For all components, the analyses show that the calculated stress levels are below the ASME code acceptance criteria.

Both valve analyses, based on the 5 in. model tests of a similar valve, are used to support the licensee's conclusion. The licensee has determined that the operability criteria of SRP 6.2.4, BTP CSB 6-4, and SRP 3.10 are satisfied with the condition that the 42 in. valve opening is blocked to 50° or less. No such condition is imposed on the 18 in. valve in order to demonstrate its operability.

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4. EVALUATION

We find that the information submitted by the licensee has demonstrated the ability of the 18 and 42 in. containment valves to close, with the condition that the 42 in. valves be limited to a 50° opening angle. The following considerations form the basis for our findings.

1. A review of the Perry FSAR Section 6.2.4 shows that the double-ended guillotine break of the recirculation line results in the maximum containment pressure. The containment response is ~4.5 psig during the first 5 s of the design basis accident and rises to a peak pressure of 11.31 psig after 11,128 s. This condition produces the most severe loads on the purge valves under review. The valve analysis is based on a constant inlet pressure of 26.7 psia and conservatively envelopes the peak LOCA condition.

2. The methodology presented in the licensee's submittal to determine the dynamic torque values is acceptable. The predicted torques are based on the worst case configuration of the valves as discussed earlier in Section 3, Item 3, as well as in the Perry FSAR Table 6.2-32 and Figure 6.2-60. The valve analysis extrapolated the results of tests performed on a similar 5 in. model valve and applied empirical torque coefficients and sizing factors to account for differences of Reynold's Numbers and air lift coefficients. However, it should be noted that derivation of the empirical factors was not presented in the submittal. Likewise, neither the 5 in. model valve design nor the execution of its flow tests were described in much detail.

3. The licensee's submittal has considered and listed all of the critical parts of the 18 in. purge valve as shown on Pratt drawings C-6020 and C-6021 which are included with Reference 2. The mounting hardware for the operator have also been considered. The acceptance criteria for the stress analysis are traceable to the ASME code, Section III and 0.40 x yield strength

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for non-code shear. The allowable stresses are not exceeded for the full range of motion of the 18 in. valve. For example, the maximum shear stress in the top disc pin is 6298 psi which is less than the allowable level of 8160 psi.

4. The licensee's submittal has considered and listed all of the critical parts of the 42 in. purge valve and its operator mounting. This valve assembly is shown on Pratt drawings C-4804 and C-4805, which are included with Reference 3. The same acceptance criteria are used to evaluate the 18 in. and 42 in. valves. However, the torque values for the 42 in. valve exceed the manufacturer's rating for the operator except at valve disc angles of 50° or less. The maximum predicted torque of 54700 in.-lb (valve blocked at 50°) is less than the minimum operator rating of 57400 in.-lb. The calculated stresses for the valve components and bonnet under combined seismic and LOCA conditions are less than the ASME levels. These stress results are conservative since they are based on a maximum valve torque of 79500 in.-lb originally calculated for the valve blocked at 55°.

5. Valve closure times of 4 seconds or less were predicted by analysis. Closure times were determined after 1 second had passed to account for the delay in initiating valve rotation. The licensee states that the calculated 4 second closure time is conservative since in actual usage the dynamic torque tends to assist closure.

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5. CONCLUSION

We have completed our review of information concerning operability of the 18 in. and 42 in. containment purge and vent valves for the Perry Nuclear Power Plant Units 1 and 2. We find that the information submitted has demonstrated the ability of the 18 in. and 42 in. valves to close against the buildup of containment pressure in the event of a LOCA/DBA, with the condition that the 42 in. valves be limited to a 50° opening angle.

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6. REFERENCES

1. Letter from M. A. Edelman, Vice President, Nuclear Group, Cleveland Electric Illuminating Company to B. J. Youngblood, Chief, Licensing Branch No. 1, Division of Licensing, U.S. Nuclear Regulatory Commission, Response to NUREG 0737, Item II.E.4.2(6), Letter No. PY-CEI/NRR-015-L, December 19, 1984.

2. Gilbert/Commonwealth Report, Isolation/Purge Valve Analysis for 18 in.-1200 Butterfly Valve, Specification No. SP-641-4549-00, Rev. XII, Pratt Job No. D-45608 (D-0086-10), September 21, 1983.

3. Gilbert/Commonwealth Report, Isolation/Purge Valve Analysis for 42 in.-1200 Butterfly Valve (Blocked at 50°), Specification No. SP-641-4549-00, Rev. XII, Pratt Job No. D-45608 (D-0086-1, -8), September 21, 1983.

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APPENDIX O

SAFETY EVALUATION REPORT:

TMI ACTION--NUREG-0737 (II.D.1)-- RELIEF AND SAFETY VALVE TESTING FOR PERRY NUCLEAR POWER PLANT, UNIT 1

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SAFETY EVALUATION REPORT
TMI ACTION--NUREG-0737 (II.D.1)
RELIEF AND SAFETY VALVE TESTING
FOR
PERRY NUCLEAR POWER PLANT, UNIT 1
DOCKET NO. 50-440

1. INTRODUCTION

1.1 Background

Light water reactor experience has included a number of instances of improper performance of relief and safety valves installed in the primary coolant systems. There have been instances of valves opening below set pressure, valves opening above set pressure and valves failing to open or reseat. From these past instances of improper valve performance, it is not known whether they occurred because of a limited qualification of the valve or because of a basic unreliability of the valve design. It is known that the failure of a power-operated relief valve to reseat was a significant contributor to the TMI-2 sequence of events; however, such an event in a Boiling Water Reactor (BWR) would not have the same severe consequences. Nevertheless, these facts led the task force which prepared NUREG-0578[(1)] to recommend that programs be developed and executed which would reexamine the performance capabilities of BWR safety and relief valves for unusual but credible events. These programs were deemed necessary to reconfirm that the General Design Criteria 14, 15 and 30 of Appendix A to Part 50 of the Code of Federal Regulations, 10 CFR are indeed satisfied.

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1.2 General Design Criteria and NUREG Requirements

General Design Criteria 14, 15, and 30 require that (1) the reactor primary coolant pressure boundary be designed, fabricated and tested so as to have an extremely low probability of abnormal leakage, (2) the reactor coolant system and associated auxiliary, control and protection systems be designed with sufficient margin to assure that the design conditions are not exceeded during normal operation or anticipated transient events and (3) the components which are part of the reactor coolant pressure boundary shall be constructed to the highest quality standards practical.

To reconfirm the integrity of relief and safety valve systems and thereby assure that the General Design Criteria are met, the NUREG-0578 position was issued as a requirement in a letter dated September 13, 1979 by the Division of Licensing (DL), Office of Nuclear Reactor Regulation (NRR) to ALL OPERATING NUCLEAR POWER PLANTS. This requirement has since been incorporated as Item II.D.1 of NUREG-0737[(2)] (Clarification of TMI Action Plan Requirements) which was issued for implementation on October 31, 1980. As stated in the NUREG reports, each boiling water reactor Licensee or Applicant shall:

1. Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

2. Determine valve expected operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2.

3. Choose the single failures such that the dynamic forces on the safety relief valves are maximized.

4. Use the highest test pressures predicted by conventional safety analysis procedures.

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5. Include in the relief and safety valve qualification program the qualification of the associated control circuitry, piping and supports.

6. Test data including criteria for success or failure of valves tested must be provided for Nuclear Regulatory Commission (NRC) staff review and evaluation. These test data should include data that would permit plant-specific evaluation of discharge piping and supports that are not directly tested.

7. Each Licensee must submit a correlation or other evidence to substantiate that the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must be accounted for if it is different from the generic test loop piping.

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2. BWR OWNERS' GROUP RELIEF AND SAFETY VALVE PROGRAM

To respond to the NUREG requirements listed above, the BWR Owners' Group contracted the General Electric Company (GE) to design and conduct a Safety/Relief Valve Test Program.(3) The program describes the safety/relief valves to be tested, the test facility requirements, the test sequence, the valve acceptance criteria and the procedure for obtaining, analyzing and reporting the test data. Prior to its acceptance, the test program received extensive NRC review and comment followed by responses from the GE/BWR Owners' Group. Six NRC questions and Owners' Group responses dealing with justification of the applicability of test results to the in-plant safety/relief valves are contained in the enclosure to Reference 4. The NRC review of the response to these questions is contained in Reference 5. Based on this review, the concerns expressed in the questions were appropriately resolved.

The early BWRs contain a combination of dual function safety/relief valves (SRV), power actuated relief valves (PARV) and single function safety valves (SV). However, Unit 1 of the Perry Nuclear Power Plant utilizes 19 SRVs and no PARVs or SVs.

The qualification of the SRVs for steam discharge under expected operating and accident conditions has been demonstrated by vendor production tests and is confirmed routinely by in-plant startup and operability tests. Based on this, it was agreed that the valves should be tested for those events that result in liquid or two-phase flow at the SRV.

The test sequence and conditions established in the test program were based on an evaluation of expected operating conditions determined through the use of analyses of accident and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2. Enclosure 2 to Reference 3 provides this evaluation which indicated that there is one event which is significantly likely to occur and can lead to the discharge of liquid or two-phase flow from the SRV. This event combined with the single failure requirement of NUREG 0737 results in the conclusion that a test should be

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performed simulating the alternate shutdown cooling mode which utilizes the SRV as a return flow path for low pressure liquid to the suppression pool.

At a meeting on March 10, 1981,[6] the BWR Owners' Group presented results of a study by Science Applications, Inc. (SAI) which showed that the probability of getting liquid to the steamline, and hence to the SRV, is approximately 10^{-2} per reactor year. However, even if the water level increases to the midplane of the steam line nozzle on the vessel, which is not likely,[a] the fluid quality at the valve was calculated by GE to be greater than 20%.[3] Because the steam lines typically drop about 45 feet vertically from the vessel nozzles to the horizontal runs on which the SRVs are mounted, much of the liquid which gets to the steam lines would be entrained as droplets. Therefore, the two-phase mixture upstream of the SRVs, should liquid reach the level of the steam lines, would exist as a froth, droplet, annular or stratified flow regime, and slug flow or subcooled liquid flow would be unlikely.

Even if two-phase discharge through a SRV should result in a stuck open valve, the results of the blowdown are not severe. As discussed in Reference 7, historically there have been a total of 53 inadvertent blowdown events due to pressure relief system valve malfunctions from 1969 through April 1978. These events varied in consequences from a short duration pressure transient to a rapid depressurization and cooldown of the primary coolant system from approximately 1100 psig to a few hundred psig. No fuel failures due to these transients have been reported.

In Reference 8, the BWR Owners' Group discusses the consequences of the worst case transient for maintaining the core covered (loss of feedwater) combined with the worst single failure (failure of the high pressure injection system) and one stuck open relief valve. Reference

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a. Feedwater pumps would be tripped prior to the water level reaching the midplane by the L8 high level trip, turbine vibration trip, or by operator action.

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plant analyses for a BWR/4 and a BWR/5 show that the Reactor Core Isolation Cooling (RCIC) system can automatically provide sufficient inventory to keep the core covered. This capability is not a design basis for the RCIC system and not all plants have been analyzed to demonstrate this capability. If a plant should not have this capability, manual depressurization to low pressure core cooling systems will avoid core uncovery for the case of loss of feedwater plus worst single failure plus a stuck open relief valve. Therefore, even for the loss of feedwater transient with the worst single failure, a stuck open relief valve does not uncover fuel.

At the March 10, 1981 meeting,[6] the BWR Owners' Group presented an analysis that showed that even if a slug of subcooled water exists upstream of the SRVs, the probability of rupturing the discharge line is 7×10^{-4} per event. The Staff has not reviewed the supporting analysis for this value; however, even if the failure probability is as high as 10^{-2} per event, the combined probability is no greater than for a steam line break inside containment. GE states that the steam line break, which has been analyzed and found to be acceptable, would be more severe (effects on the core and containment) than a break in a valve discharge line with a stuck open SRV because the assumed break area is larger.

In summary, based on the BWR operating history of inadvertent SRV blowdowns, the low likelihood of severe consequences, and the bounding design basis steam line break, the staff decided not to require high pressure testing with saturated liquid or subcooled water.

Based on the above, the Licensee has complied with NUREG Requirements 1-4 (Paragraph 1.2 above). That is, an acceptable test program was established which adhered to the Staff guidelines on the selection of test conditions and the maximization of system loads. That portion of Item 5 dealing with the qualification of the associated control circuitry is considered to be satisfied as a result of the anticipated licensing action for compliance with 10 CFR, Part 50.49.

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3. BWR OWNERS' GROUP TEST RESULT AND ANALYSIS

In October 1981, the BWR Owners' Group published a technical report[9] documenting the results of the prototypical safety/relief valve tests conducted in accordance with the accepted Test Program.[3] The tests were performed by the General Electric Company for the BWR Owners' Group at the Wyle Laboratory in Huntsville, Alabama. The test report, which was reviewed by the Staff, describes the test facility, the basis for the test conditions and valve selection, the instrumentation and its accuracy, and analyzes the results with respect to valve operability, piping and support loads and the applicability of the test results to the in-plant safety and relief valves.

With the completion of the testing and the submittal of the test report, the Licensees complied with NUREG Requirement No. 6 listed in 1.2 above. However, the subsequent Staff review of the test results generated six plant specific questions stated in Reference 10 which required resolution. Reference 11, representing the Perry Nuclear Power Plant response to the six plant specific questions, was submitted for review on March 11, 1983.

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4. REVIEW AND EVALUATION

4.1 Review of Test Results and Analysis

An extensive review[12,13] of the test results[9] was conducted by NRC consultants (EG&G Idaho, Inc.) at the Idaho National Engineering Laboratory. The review addressed not only the test results but also the applicability of the test results and equipment to the Perry Nuclear Power Plant, Unit 1 safety-relief valve systems. The six plant specific questions generated by the review and the Licensee responses to those questions are discussed in Paragraph 4.4 below.

4.2 Valves Tested

The generic test program required the testing of six different safety/relief valves. Included was a Dikkers 8XRX10 Direct Acting Dual Function Safety Relief Valve, Style G471-6/125.04. There are no material, dimensional or operational differences between the in-plant valves and the tested valves. Thus, the tested valve was considered to be applicable to the in-plant valves at the Perry Nuclear Power Plant, Unit 1.

4.3 Test Conditions

As discussed in Section 2.0 herein, test conditions to envelop the expected BWR Safety/Relief Valve events were developed in accordance with NRC guidelines. They were accepted and are presented in Reference 3. The review of the test results indicates that the actual test conditions were in accordance with the established test program.

4.4 Evaluation of Responses to Plant Specific Questions

The response to Question No. 1 indicates that there are SRV discharge line differences between the test configuration and the in-plant configuration. However, it is pointed out that these differences result in bounding loads on the SRVs. The first segment of test piping downstream of the SRV is longer than the comparable in-plant segment (12 ft vs 4 ft) which

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would result in a higher moment at the test valve. Discharge from the "x" quencher at the end of the Perry Nuclear Power Plant SRV discharge line cannot transmit loads to the valve as the test system could because the in-plant line contains an anchor between the quencher and the valve. Thus, this portion of the response is considered to be acceptable. The second part of the response addressed the back pressure (dynamic, hydraulic) loads on the test and in-plant valves. The Licensee addressed both transient and steady state back-pressure loads. The steady state back pressure for the test valve was forced to be greater than that expected in-plant by installing a predetermined orifice plate in the discharge line before the ram's head and above the water line. The response also indicated that the high pressure steam test preceding the low pressure water test would produce the greater transient back pressures between the two tests. This would be true due to the higher pressure upstream of the SRV and the shorter valve opening time.

Based on the above discussion, the response to the first question is considered by the Staff to be acceptable.

The response to the second question described the support system components in the Perry Nuclear Power Plant, Unit 1 discharge lines indicating that spring hangers do exist at Perry whereas the test facility piping did not include spring hangers. The basic argument defending the adequacy of the spring hangers (in fact, all supports) is that they were designed for the much larger, high steam pressure relief valve opening loads. In this case, therefore, sufficient margin is available in the in-plant spring hangers to account for the additional load due to the dead weight in the water-filled, low pressure event. The test results indicated significantly lower dynamic loads during the water discharge event than during the high pressure steam discharge case and the point made in this response (as well as in the response to Question No.1) is that the test program was designed primarily to demonstrate valve and system adequacy under the prototypical water discharge events (i.e., the alternate shutdown cooling mode).

Thus, with the in-plant SRV discharge piping and support system designed for the high pressure steam discharge event and with the satisfactory

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response of the test valves, the discharge piping and support system to the low pressure water blowdown, the reply to the second question is considered by the Staff to be acceptable.

The third question inferred that, during testing, there may have been valve functional deficiencies or anomalies encountered that invalidated test runs and were not reported in the test results because subsequent valid test runs were obtained. The response to this question states, "All the valves subjected to test runs, valid or invalid, opened and closed without loss of pressure integrity or damage." This statement is supported by the Wyle Laboratory test log sheet for the Dikkers 8XRX10 Direct Acting Dual Function Safety/Relief Valve. Thus, the Staff finds the response to Question No. 3 to be acceptable.

Question No. 4 asked the Licensee to describe and compare expected events at the Perry Nuclear Power Plant with the test conditions of the generic test program. The Licensee summarizes the analysis procedure[3] using Regulatory Guide 1.70 which arrived at 13 events that would result in liquid or two-phase flow through the SRVs and maximize the dynamic forces on the valve. As indicated in Section 2.0 herein, this analysis concluded that the alternate shutdown cooling mode is the only expected event which will result in liquid at the valve inlet. To simulate this event the test program[3] used a 15-50°F subcooled liquid at 20-250 psig at the safety valve inlet prior to valve opening. The Licensee indicates that the alternate cooling mode of operation at Perry will result in a relief valve liquid discharge that would be approximately 35°F subcooled at a pressure of approximately 135 psig. Therefore, the test conditions envelop the expected conditions for this event should it occur in Unit 1 at the Perry Nuclear Power Plant. The Licensee's response to the fourth question is acceptable to the staff.

The fifth question addresses the effect on valve performance of steam flow cycling of the valves prior to the low pressure liquid flow event. The sequence to arrive at the alternate shutdown cooling mode is described in the response. It indicates that the SRV would be cycled under steam conditions to maintain a 100°F cooldown rate. The test program and, of course, the

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actual tests included only one steam cycle, the purpose of which was to bring the valve up to the proper service temperature prior to the low pressure liquid test. Thus, any adverse effect of several high pressure steam cycles on valve performance during the liquid test was not included. The response indicates that the valve vendors subject their valves to steam flow cycling and that no loss of valve performance has been noted. The response to this question is acceptable to the Staff.

The response to the sixth question addresses the determination and future use of the valve flow coefficient, C_v. The response indicates that the value of the liquid flow coefficient, in itself, is not of direct interest. The flow capacity of the valves as measured during the tests is the data of interest. The flow capacity of the system SRVs is larger than the capacity of the coolant source pump of the residual heat removal (RHR) system and therefore sufficient to remove decay heat. The answer to this question is considered to be acceptable to the Staff.

Considering the above evaluations, the Staff finds that the Licensee for the Perry Nuclear Power Plant, Unit 1 has provided an acceptable response to NUREG Item 7 and to the piping and support concerns of NUREG Item 5 (Paragraph 1.2 herein).

4.5 Supporting Information-High Pressure Steam Flow/Discharge Piping Response

The applicability of the response of the SRV discharge piping system to the response of the in-plant piping system has been accepted above. In the test report,[9] it is indicated that, (1) the analytically predicted response of the test piping and supports was comparable to the measured values, and (2) the maximum test piping response to liquid flow was generally less than 30% of that due to test steam flow conditions. Further, as part of the initial review, the loads on the in-plant piping and supports due to steam discharge were found to be acceptable by the Staff. It should also be mentioned that the adequacy of the Perry SRV discharge piping under high pressure steam loads will be investigated as part of the Staff's normal licensing review.

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5. EVALUATION SUMMARY

The Licensee for the Perry Nuclear Power Plant, Unit 1 has provided an acceptable response to the requirements of NUREG-0737, and thereby, reconfirmed that the General Design Criteria 14, 15 and 30 of Appendix A to 10 CFR-50 have been met. The rationale for this conclusion is given below.

The Licensee with concurrence by the Staff developed an acceptable Relief and Safety Valve Test Program designed to qualify the operability of the prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated design basis events. The generic test results showed that the valves tested functioned correctly and safely for all steam and water discharge events specified in the test program and that the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the Licensee justifications indicated the direct applicability of prototypical valve and valve system performances to the in-plant valves and systems intended to be covered by the generic test program.

Thus, the requirements of Item II.D.1 of NUREG 0737 have been mat (Items 1-7 in Paragraph 1.2) and, thereby, assure that the reactor primary coolant pressure boundary will have, by testing, a low probability of abnormal leakage (General Design Criterion No. 14) and that the reactor primary coolant pressure boundary and its associated components (piping, valves and supports) have been designed with sufficient margin such that design conditions are not exceeded during relief/safety valve events (General Design Criterion No. 15).

Further, the prototypical tests and the successful performance of the valves and associated components demonstrated that this equipment has been constructed in accordance with high quality standards (General Design Criterion 30).

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4. Letter, D. B. Waters, Chairman BWR Owners' Group to D. G. Eisenhut, Director, Division of Licensing, NRR, USNRC, "Responses to NRC Questions on the BWR S/RV Test Program," BWR06-8135, March 31, 1981.

5. Letter, B. F. Saffell to R. E. Tiller, Comments on BWR Owners' Group Responses to NRC Questions on Safety/Relief Valve Low Pressure Program - Saff-95-81, April 23, 1981.

6. Memorandum to Themis P. Speis from Wayne Hodges, "Summary of March 10 Meeting with General Electric to Discuss BWR Liquid Overfill Events," May 1981.

7. Technical Report on Operating Experience with BWR Pressure Relief Systems, NUREG-0462, July 1978.

8. Letter to Darrell G. Eisenhut (NRC) from David B. Waters (BWR Owners' Group), BWROG-80-12, "BWR Owners' Group Evaluation of NUREG-0737 Requirements," December 29, 1980.

9. Analysis of Generic BWR Safety Relief Valve Operability Test Results, General Electric NEDE-2 4988-P, October 1981.

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11. Letter, M. R. Edelman to B. J. Youngblood, "Perry Nuclear Power Plant, Docket Nos. 50-440; 50-441, Response to EQB Questions Nos. 271.1-271.6...," March 11, 1983.

12. Letter, B. F. Saffell to R. E. Tiller, "Review of BWR/GE Safety Relief Valve Test Report (A6356)" Saff-14-82, January 13, 1982.

13. Letter, B. F. Saffell to D. E. Solecki, "Open Questions-BWR/GE Safety/Relief Valve Test Report, BWR Owners' Safety/Relief Submittals (A6356)"-Saff-178-82, May 4, 1982.

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APPENDIX P

TECHNICAL EVALUATION REPORT
OF THE
DETAILED CONTROL ROOM DESIGN REVIEW
FOR
CLEVELAND ELECTRIC ILLUMINATING COMPANY
PERRY NUCLEAR POWER PLANT UNIT 1

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TECHNICAL EVALUATION REPORT

OF THE

DETAILED CONTROL ROOM DESIGN REVIEW

FOR

CLEVELAND ELECTRIC ILLUMINATING COMPANY

PERRY NUCLEAR POWER PLANT UNIT 1

June 11, 1985

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United States

Nuclear Regulatory Commission

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TECHNICAL EVALUATION REPORT

OF THE

DETAILED CONTROL ROOM DESIGN REVIEW

FOR

CLEVELAND ELECTRIC ILLUMINATION COMPANY

PERRY NUCLEAR POWER PLANT UNIT 1

1.0 BACKGROUND

Licensees and applicants for operating licenses shall conduct a Detailed Control Room Design Review (DCRDR). The objective is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (NUREG-0660, Item I.D.). The need to conduct a DCRDR was confirmed in NUREG-0737 and Supplement 1 to NUREG-0737. DCRDR requirements in Supplement 1 to NUREG-0737 replaced those in earlier documents. Supplement 1 to NUREG-0737 requires each applicant or licensee to conduct a DCRDR on a schedule negotiated with the Nuclear Regulatory Commission (NRC).

NUREG-0700 describes four phases of the DCRDR and provides applicants and licensees with guidelines for its conduct. The phases are:

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1. Planning

2. Review

3. Assessment and implementation

4. Reporting

The requirements of Supplement 1 to NUREG-0737 indicate the need to include a number of elements in the DCRDR. They are:

1. Establishment of a qualified multidisciplinary review team

2. Function and task analyses to identify control room operator tasks and information and control requirements during emergency operations

3. A comparison of display and control requirements with a control room inventory

4. A control room survey to identify deviations from accepted human factors principles

5. Assessment of human engineering discrepancies (HEDs) to determine which are significant and should be corrected

6. Selection of design improvements

7. Verification that selected design improvements will provide the necessary correction and do not introduce new HEDs

8. Coordination of control room improvements with changes from other programs such as the safety parameter display system (SPDS), operator training, Reg. Guide 1.97 instrumentation, and upgraded emergency operating procedures (EOPs)

Licensees are expected to complete Element 1 during the DCRDR's planning phase, Elements 2 through 4 during the DCRDR's review phase, and Elements 5 through 7 during the DCRDR's assessment and implementation phase. Completion of Element 8 is expected to cut across the planning, review, and assessment and implementation phases.

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A Summary Report is to be submitted at the end of the DCRDR. As a minimum it shall:

1. Outline proposed control room changes
2. Outline proposed schedules for implementation
3. Provide summary justification for HEDs with safety significance to be left uncorrected or partially corrected

The NRC staff evaluated the organization, process and results of the DCRDR. Results of the evaluation are documented in a Safety Evaluation Report (SER) published within two months after receipt of the Summary Report.

2.0 DISCUSSION

Cleveland Electric Illuminating Company (CEI) submitted a DCRDR Program Plan for Perry Nuclear Power Plant Unit 1 (PNPP) on June 7, 1982 (Ref. 7). NRC staff comments on that Program Plan were forwarded to CEI on December 23, 1983 (Ref. 8).

CEI submitted a Summary Report for PNPP January 10, 1985. Based on the results of previous activities and on review of the Summary Report, the NRC staff conducted a pre-implementation audit of the PNPP DCRDR April 9-12, 1985.

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2.1 Establishment of a Qualified Multidisciplinary Review Team

Supplement 1 to NUREG-0737 requires the establishment of a qualified multidisciplinary review team. Guidelines in team selection are found in NUREG-0700 and NUREG-0800, Standard Review Plan, Section 18.1, Appendix A Rev. 0 .

The Perry Nuclear Power Plant (PNPP) Summary Report describes a multidisciplinary team that appears to possess the necessary skills to perform a DCRDR. Team members are identified with their area of expertise and involvement in each phase of the DCRDR on Table 2-1 of the Summary Report. Attachment L of the Summary Report also includes resumes and a description of tasks performed and level of effort of team members.

The review team includes the following groups:

- o PNPP Human Factors Unit
- o PNNP Support Personnel
- o Human Factors Specialists
- o Consultants
- o Personnel from other Utilities

The disciplines involved include various full-time engineering and operations personnel, part-time engineering, operations, technical, and training personnel, all from PNPP; three human factors specialists that work closely

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with the team throughout each phase of the DCRDR; systems and operations engineers from GE who participate in all phases of the DCRDR except selection of design improvements; and a systems engineer and operations engineer from two other BWR utilities who provided support through the BWROG Control Room Survey Program.

The PNPP Human Factors Unit is responsible for the implementation of the DCRDR and the Human Factors Unit lead engineer provides the administration and technical direction for the DCRDR. CEI has given technical task assignments that are appropriate to the review team disciplines. The DCRDR team, as a whole, does not appear to have been provided with a specific DCRDR orientation. However, key individual members of the team did, participate in activities which provided information on DCRDR background and methods.

Based on the Summary Report and discussions during the pre-implementation audit, the NRC audit team found that the review team members have the suitable expertise to perform an adequate DCRDR. We conclude that the PNPP review team meets the requirement of Supplement 1 to NUREG-0737 to establish a multidisciplinary review team for conducting a DCRDR. CEI should assure continued participation of personnel from appropriate disciplines, including human factors and operations, during the completion of the DCRDR to fully satisfy the requirement.

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2.2 Systems Function and Task Analyses

Supplement 1 to NUREG-0737 requires the applicant to perform systems function and task analyses to identify control room operator tasks and information and control requirements during emergency operations. Furthermore, Supplement 1 to NUREG-0737 recommends the use of function and task analyses that had been used as the basis for developing emergency operating procedures, technical guidelines, and plant-specific emergency operations procedures to define these requirements.

The following steps for a top-down systems function and task analysis are identified in NUREG-0700 guidelines.

1. Identification of Systems and Subsystems

2. Identification of Operating Events for Analysis

3. Function Identification

4. Operator Task Identification and Analysis

Operator information and control needs must be determined independently from the existing CR design, and not be influenced by existing equipment.

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CEI has used the BWROG Emergency Procedure Guidelines (EPG) as the basis for the DCRDR task analysis and to develop Perry Plant Emergency Instructions (PEI). These EPG's were the topic of a May 4, 1984 meeting between the NRC and the BWROG (see ref. #5). Based on that meeting, the staff concluded that:

1. It appears that revision 3 of the EPG provides a functional analysis that identifies, on a high level, generic information and control needs. However, these EPG's do not explicitly identify the plant-specific information and control needs, which are necessary for preparing emergency operating procedures and determining the adequacy of existing instrumentation and controls.

2. Because detailed plant-specific information and control needs cannot be extracted directly from the EPG's, plant-specific analysis is required.

3. Each licensee and applicant must describe the process used to identify plant-specific parameters and other plant-specific information and control capability needs and must describe how the characteristics of needed instruments and controls will be determined. These processes may be described in either the Procedure Generation Packages (PGP) or the DCRDR Program Plan with appropriate cross-referencing.

4. For each instrument and control used to implement the EOP's, there should be an auditable record that defines the necessary characteristics of the instrument or control and the bases for that determination. The

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necessary characteristics should be derived from analysis of the information and control needs identified in NRC approved EPG's and from analysis of plant-specific information.

In order for the SFTA to be acceptably accomplished for all emergency conditions, the systems function and task analyses should:

- Be independent of existing equipment.
- Identify and analyze the appropriate operating events, plant safety-related systems, and functions which must be exercised and analyzed.
- Identify the EOP's and tasks which must be executed and analyzed.
- Name the independent reference sources used, and describe who will use them and how they will be used to specify and document the transition from BWROG generic guidelines to the plant-specific characteristics of information and controls needed by the operator to mitigate the effects of the emergency conditions.
- Completely cover all emergency operations included in the EPG's.

To enhance the acceptability of the description of the methodology, the applicant's documentation should include the following:

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- Discussions of the approaches and information sources used (e.g., documents, guidelines, operations personnel, multiple approaches, plant-specific calculations, etc.).

- The rationale and methodology used in the selection of event sequences, along with a description of how it was verified that the selected sequences adequately cover the complete range of systems needed to mitigate abnormal plant conditions.

- The process used to identify the functions, systems, subsystems, and events selected for analysis. It should be made clear that the applicant is using an independent objective top-down approach rather than a bottom-up procedure-based approach.

- A discussion of who will perform the work and how the independent reference sources, the documented independently determined information and control needs and characteristics, and the inventory process were coordinated to ensure independence, completeness, and accuracy.

An essential part of the above is the method by which the independent reference sources were documented and used to ensure the independence of the identified characteristics of the information and control needs from those of existing equipment.

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During discussions at the pre-implementation audit PNPP provided clarification of their methodology, as explained in the Summary Report, for conducting a SFTA.

PNPP will use their PEI's that were developed from the BWROG's EPG's to satisfy the need for a function analysis. The transition from the BWROG EPG's to the plant PEI's was accomplished using the Procedure Generation Package (PGP). This methodology is a departure from what is recommended in the guidelines. The process used by PNPP can be made to satisfy the need for a function analysis, but it relies on development of complete and technically adequate PEIs. Because the PEIs are still under development, the function and task analysis element of the PNPP DCRDR cannot be considered complete. We understand that CEI intends to update the task analysis as PEIs are "finalized" prior to fuel load.

Several concerns were identified during the pre-implementation audit. The first being that CEI needs to document which version of the EPG's will be used for the final revision of the PEIs. As PEIs, SOIs, CNIs, and IOI-11 are updated prior to fuel load, the task analysis should also be updated to fully satisfy the requirement. CEI stated during discussions that a mini-review will be performed after the PEI update has taken place. One area to be addressed during the mini-review is to consider the impact of PEI changes on work already completed based on HEDs identified during the task analysis. The task analysis update should identify new and modified tasks, the information and control capabilities required to perform these tasks, and appropriate

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characteristics of displays and controls to satisfy the information and control capability requirements.

We conclude that with the exceptions mentioned above that PNPP should meet this requirement to Supplement 1 of NUREG-0737.

2.3 Comparison of Display and Control Requirements with a Control Room Inventory

Supplement 1 to NUREG-0737 requires the applicant to make a control room inventory and to compare the operator display and control requirements determined from the task analyses with the control room inventory to determine missing controls or displays.

PNPP conducted their control room comparison through the use of the PNPP CRDR Task Analysis Data Sheet. The operator response section of this form was completed during this process. To accomplish this element of the review operators were given a task which had been identified in the task analysis. Operators were asked to identify on the actual control room panels which instruments and controls would be used to successfully accomplish this task. The location and informational characteristics of the instruments and controls were recorded on the appropriate form at this time. The identified instruments and controls were then reviewed by the PNPP review team for availability and suitability. Human engineering observations were recorded in cases where displays and controls were unavailable or unsuitable to satisfy requirements for information and control capabilities.

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The Summary Report describes the comparison of display and control requirements with the control room inventory. The control room itself was used as the inventory against which display and control requirements were compared. That approach is generally acceptable. Supplemental information may, however, be required to identify the characteristics of some instruments and controls.

The organization, process, and results of this element of the DCRDR was found to be acceptable by the pre-implementation audit team. Complete satisfaction of the requirement in Supplement 1 to NUREG-0737 will require comparison of display and control requirements identified in the task analysis update (discussed in the previous section) with the control room inventory.

2.4 Control Room Survey

Supplement 1 to NUREG-0737 requires that a control room survey be conducted to identify deviations from accepted human factors principles. NUREG-0700 provides guidelines and criteria for conducting a control room survey. The objective of the control room survey is to identify for assessment and possible correction, the characteristics of displays, controls, equipment, panel layout, annunicators and alarms, control room layout, and control room ambient conditions that do not conform to good human engineering practices. CEI has executed their DCRDR survey in several parts all of which served to identify potential Human Engineering Deficiencies (HEDs).

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- o BWROG CR Survey (September 21-25, 1981)
- o NRC in-progress Audit (with discussions) (August 9-13, 1982)
- o BWROG CR Survey Supplement (June 11-15, 1984)

The above sources identified over 1000 observations and discrepancies which CEI reduced by a screening process to 334 valid HEDS. These HEDs are reported in Attachment I of the Summary Report.

The NRC reviewed these 334 HEDs in the Perry control room during the pre-implementation audit. The results of that review are as follows:

- o 38 HEDs that are considered closed with no further action required. See Appendix A for details.

- o 250 HEDs that are considered open pending implementation and audit. NRC agrees with the proposed resolutions and implementation schedules. All items must be implemented and verified per the HED report sheet schedule. See Appendix B for details.

- o 46 HEDs that are considered open pending revised response, additonal review, and implementation. These include the environmental survey items and HEDs that need a revised response or review by CEI. See Appendix C for details.

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The balance of the Human Engineering Observations (HEOs) that didn't become valid HEDs were assessed by CEI and categorized as follows:

- Disagree----------160
- Duplicate----------379
- Procedure Related----------216

These HEOs were reviewed by the NRC audit team with a check of the documentation, which appeared adequate. There was an auditable paper trail that could track all HEO and HED numbers.

The NRC audit team agrees with the disposition of these HEOs but had some concern with the 216 that were procedure related and were sent to the operations procedures group for assessment. The concern was that these observations were not assigned HEO numbers and there was some question about the auditability of them after they were transferred to the operations group. During the pre-implementation audit the NRC recommended that there be a follow-up of these observations by the PNPP review team and CEI agreed to this.

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The summary report generally describes what CEI did during the conduct of the CR Surveys and what the results were. The descriptions of who performed the work are also generally acceptable. During the pre-implementation audit the NRC review team found that human factors and other recommended skills and expertise were continually present during the generation of the observations and discrepancies. CEI also stated that the remote shutdown panels have been included in CR Survey. An audit of the RSP HEDs was performed by the NRC team at the panels.

During the pre-implementation audit, the NRC reviewed the CR Survey and operating experience review documentation. An acceptable comparison of selected CR Survey checklists with accepted human factors principles was made. A review of all HEDs for disposition was conducted at the actual control panels and there was a review of HEOs that didn't become HEDs. In all cases the documentation was available and adequate.

Complete satisfaction of the control room survey effort requires environmental surveys in the completed control room and a survey of communication equipment when it is available in the control room. CEI will provide documentation of survey results to NRC of the Environmental, Emergency Equipment, Communications, and Computer Systems Surveys by fuel load.

We conclude that CEI has performed an acceptable systematic comparison of the control room against accepted human engineering guidelines.

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2.5 Assessment of HEDs

Supplement 1 to NUREG-0737 requires that HEDs be assessed to determine which HEDs are significant and should be corrected. NUREG-0700 and NUREG-0800, SRP Section 18.1, Appendix A, Rev. 0, contain guidelines for the assessment process.

Our review of the Human Engineering Discrepancy Report (HEDR) and Human Engineering Deficiency Reports (HEDs) included in the Perry Summary Report confirmed that Cleveland Electric Illuminating Company (CEI) has analyzed, prioritized, and recommended means for correcting or modifying those HEDs which will impact safety or plant/operation performance. Human factors personnel and General Electric consultants assisted CEI in these efforts. Procedural items were stated to be referred to the CEI Operations Section for resolution. A formal assessment process is described and diagrammed in the summary report. (Table 2-1 and Figure 2, and Attachment L).

Figure 2 of the Summary Report illustrates the assessment process showing that all discrepancies and observations were reviewed to determine which ones qualify as HEDs for which corrections or modifications would be selected for implementation. Some observations were identified as not being significant enough to modify or fix, and were placed in the "None" classification.

The HED's selected for correction were placed in the "Fix" classification to bring into full compliance with HF guidelines or benchmarks. The HEDs

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selected for improvement were placed in the "Modify" classification to be brought into partial compliance with guidelines or benchmarks. Observations placed in the "None" classification will not be corrected or modified.

HEDs originally placed in the "Modify" and "None" classifications were further assessed for safety compliance and operability significance. If deemed to have unsatisfactory safety or operability consequences, these HEDs were reconsidered for reclassification to "Fix" or "Modify" and implemented accordingly.

CEI's "Integrated Assessme: Methodology" describes a process that permits a significant number of HEOs to be assessed into categories before HEO numbers are assigned. These categories are as follows:

- Duplicate human engineering discrepancies/observations

- Human engineering discrepancies/observations that were determined to be invalid or inappropriate for the PNPP control room

- Procedure related human engineering discrepancies/observations

There was some concern as to the auditability of the procedure related HEOs that were sent to the CEI Operations section for resolution. CEI has agreed to maintain an auditable documentation trail showing the disposition of these items after they have been assessed by the procedures group.

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The NRC audit team reviewed the procedure related HEOs and the valid HEDs during the pre-implementation audit and generally agreed with the proposed resolutions. The audit team found that CEI has used an assessment method that assures an acceptable resolution to these HEOs and HEDs and has provided an auditable documentation trail. The remaining activity is to assess any HEOs/HEDs identified as a result of the comparison of displays and controls with the control room inventory and as a result of completing the control room survey.

CEIs "Integrated Assessment Methodology" is a process that combines assessment of human engineering discrepancies/observations and the selection of design improvements. Perry's assessment process was not consistent with guidelines since the determination of whether an item should be corrected on the basis of error probability and potential consequences of that error, was not made. PNPP did, however, assess all items which were to remain uncorrected or to be only partially corrected. If there was a significant safety or operability consequence the item was iteratively subjected to selection of design improvements and assessment until resolved. The pre-implementation audit team reviewed the assessment process carefully. Although the assessment process was not consistent with the NRC guidelines, the results of the assessment process were adequate to satisfy the assessment requirement of Supplement 1 to NUREG-0737.

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2.6 Selection of Design Improvements

Supplement 1 to NUREG-0737 requires selection of control room design improvements that will correct significant HEDs. It also states that improvements that can be accomplished with an enhancement program should be done promptly.

The Summary Report states:

The determination of "Fix" and "Modify" HED design was an integrated effort taking into account the following considerations:

- Does the modification fully correct or improve the HED as intended?
- Is the modification coordinated with changes from other improvement programs such as SPDS, R.G. 1.97, Operator Training and PNPP Emergency Procedures?
- Have alternate methods for modification been explored, such as SPDS or Operator Training?

CEI's methodology for selecting design improvements as stated in the PNPP Summary Report appears acceptable. Through discussions during the audit, the processes by which the team members reviewed the HEDs and selected corrective action designs and modifications within the guidance of the above

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considerations were appropriate. The pre-implementation audit team reviewed all proposed corrective actions resulting from the DCRDR. In general that review indicated that results were acceptable (see Appendixes A and B). However, some concerns were identified. Those concerns were discussed with CEI and should be addressed as indicated in Appendix C. The pre-implementation audit also identified a number of recommendations (see Appendix D). Those recommendations should be reviewed by CEI as part of the ongoing DCRDR activity. A report of the results of that review should be provided to the NRC.

CEI states that an ongoing HF Program is committed to review and resolve HEDs over the life of the plant. They also state that there is a Design Procedure to ensure that a HF design review is performed on design changes that affect the control room.

We conclude that CEI has developed a methodology that meets the requirement of Supplement 1 to NUREG-0737 to select design improvements that will correct safety significant HEDs.

2.7 Verification that Design Improvements Provide Necessary Correction and Do Not Introduce New HEDs

Supplement 1 to NUREG-0737 requires verification that selected design improvements will provide the necessary corrections of HEDs and will not introduce new HEDs into the control room.

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The CEI summary report states that the improved control room design was evaluated to assure that the selected design improvements, both individually and collectively, adequately correct the deficiencies and do not introduce other HEDs. This was accomplished by performing the following:

- A review of HED report sheets to verify that the corrective actions comply with specific HF guidelines, and can be implemented without creating new HEDs.

- A comprehensive survey of the improved control room design on the primary control panels (P-680, P-601, P-870, P-877, P-883) using BWROG checklists. The survey considers possible interactive effects to ensure that no new HEDs are introduced and that no safety questions or potential risks remain unrecognized.

Attachment M of the Summary Report exhibits the Design Improvement Review sheet and provides instructions for its use. This sheet is used to determine:

- Whether the HEDs will be fully or partially corrected, or will not be corrected.

- What the safety consequences are.

- Whether a design selection creates new HEDs.

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- Whether unsafe operation or violation of a technical specification might result.

The verification function was performed by an independent verification team which includes a HF specialist, a licensed shift supervisor, and a senior design engineer from CEI Reliability and Design Assurance.

Because most corrections have not been implemented, CEI has performed their verification through iteration of the processes of selection of design improvements, verification that the selected design improvements will provide the necessary correction, and verification that improvements will not introduce new HEDs. They have described a process that reviews revised panel drawings against BWROG panel survey checklists. The Summary Report states that this was the comprehensive review of the primary panels. It is not clear whether verification extended to all panels or just the primary control panels.

It appears that CEI has not completed their verification requirement. It would be very difficult to sit down, without a simulator or mocked-up panels, and perform an engineering analysis that would verify that no new HEDs were introduced without being able to see how all the proposed corrections work together.

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CEI has described a method, that is part of the PNPP assessment process, to ensure that the design improvements provide the necessary corrections and will not introduce new HEDs into the control room. CEI should continue with follow-up surveys as design improvements are put in place. We also recommend a hands-on walk/talk through verification/validation after all control room design changes are installed, to demonstrate that operators can use the implemented HED control room corrections to effectively execute the EOP tasks.

When CEI completes their verification/validation on the completed control room, including an auditable documentation trail of design changes and review by the DCRDR team, the design improvement verification requirement of Supplement 1 to NUREG-0737 will be satisfied.

2.8 Coordination of the DCRDR with Other Programs

Supplement 1 to NUREG-0737 requires that control room improvements be coordinated with changes from other programs such as SPDS, operator training, RG 1.97 instrumentation, and upgraded EOP's.

The present coordination status as presented by CEI is as follows:

- The PNPP Human Factors unit has been involved in the review of the SPDS ERIS, and participated in displayed parameters selection, format, and integration of terminals into the CR and RSP.

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- The PNPP HF unit reviewed RG 1.97 improvements prior to their implementation in the CR. RG 1.97 variables were identified where applicable in the information and control portion of the task analysis.

- The DCRDR task analysis and walk-through utilized Plant Emergency Instructions (PEI) and System Operation Instructions (SOI).

- The task analysis ensured that PEI information and control requirements will be available and suitable in the control room.

- Human engineering observations concerning procedures were forwarded to the procedure writing section for resolution. The procedure writing section received DCRDR improvement selections before the changes appeared on plant drawings.

- The PEI Validation Plan of the Procedure Generation Package (PGP) requires that all PEI Revisions be reviewed by the HF unit.

- ATWS modifications were reviewed and improved by the HF unit to ensure proper integration into the control room.

- The training section was utilized throughout the DCRDR regarding the operator training program and systems technology.

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- A licensed operator is designated as HF interface between the HF unit and the various operator programs.

- Training will provide feedback on any HF observations associated with DCRDR improvements.

- The simulator will be updated to reflect the completed control room..

During discussions at the pre-implementation audit CEI stated they have assigned one of their engineers to handle the overall coordination effort. CEI stated that they will provide a schedule of completion dates for the various coordination activities to the NRC for review.

We conclude that PNPP has met the requirement for this task in Supplement 1 to NUREG-0737.

2.9 Other

The NUREG-0700 guidelines recommend that a review of operating experience be performed that includes the examination of available operating experience documents and a survey of control room operating personnel. An operating experience review is not a requirement but CEI conducted theirs in two parts:

- Preliminary operator interviews, which were done at the time of the BWROG CR survey in 1981.

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- Supplemental operator experience review in June 1984 which was based on accumulated experience during intervening years.

The PNPP operator experience review was responsible for the generation of many procedure related HEOs and several HEDs.

CEI has developed an on-going human factors program that is supported by a PNPP design procedure to ensure that a Human Factors Design Review is performed on design changes that affect the control room or remote reactor shutdown system interfaces. This document will be maintained and updated over the life of the plant.

3.0 Conclusions

Based upon our review of the PNPP Summary Report and the pre-implementation audit conducted April 9-12, 1985 it appears PNPP has satisfied the requirements of Supplement 1 of NUREG-0737 with the following exceptions:

- To fully satisfy the requirement for Systems Function and Task Analysis, CEI must update the task analysis as the PEIs, SOIs, ONIs, and IOI-11 are finalized prior to fuel load.

- To fully satisfy the requirement for Comparison of Display and Control Requirements With a Control Room Inventory, CEI must compare the display

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and control requirements identified in the task analysis update with the control room inventory.

- To fully satisfy the requirement for Control Room Survey, CEI must perform environmental surveys in the completed control room and perform a survey of communication equipment when it is available in the control room.

- To fully satisfy the requirement for Selection of Design Improvements, CEI must address the 46 HEDs in Appendix C that are considered open pending revised response, additional review, and implementation. These items must be evaluated, resolved, implemented, and verified with a schedule that is acceptable to the NRC.

- To fully satisfy the requirement for Verification that Design Improvements Provide Necessary Correction and Do Not Introduce New HEDs, CEI should perform a hands-on walk/talk through verification/validation in the completed control room.

- CEI should assure continued participation of personnel from appropriate disciplines, including human factors and operations, during the completion of the DCRDR.

- CEI should provide a schedule of completion dates for the various elements involved in the DCRDR coordination effort.

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- o CEI should enhance the completeness of their Summary report by supplying comprehensive outlines of the proposed control room changes and summary justification for HEDs with safety significance to be left uncorrected or partially corrected.

In our judgement, completion of the above items is essential for satisfaction of the DCRDR requirements of Supplement 1 to NUREG-0737. Evaluation of the PNPP DCRDR should continue through completion of the above elements.

Several recommendations also resulted from the NRC staff's evaluation of the PNPP during the pre-implementation audit. These recommendations are not intended as additional requirements. They are intended to encourage the fullest possible benefit from the DCRDR. Those recommendations are:

- o CEI is encouraged to see that the simulator be made and kept as an exact duplicate of the completed control room.

- o CEI needs to clarify whether verification extends to all panels or only to the primary control panels.

- o CEI is encouraged to follow the 29 recommendations listed in Appendix D.

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REFERENCES

1. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," May 1980; Revision 1, August 1980.

2. NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980; Supplement 1, December 1962 (Generic Letter No. 82-33).

3. NUREG-0700, "Guidelines for Control Room Design Review," September 1981.

4. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 18.1, Appendix A, Rev. 0, "Evaluation Criteria for Detailed Control Room Design Reviews," September 1984.

5. Memorandum for Voss A. Moore, from S.H. Weiss, "Meeting Summary - Task Analysis Requirements of Supplement 1 to NUREG-0737 - May 4, 1984 Meeting with BWR Owner's Group Emergency Procedure Guidelines and Control Room Design Review Committees," May 1984.

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6. Perry Nuclear Power Plant Detailed Control Room Design Review Summary Report. Submitted January 10, 1985.

7. Letter from D. R. Davidson to A. Schwencer, Subject "Control Room Design Review" June 7, 1982.

8. Letter from B. J. Youngblood to M. R. Edelman, Subject "NRC Staff Comments on the Detailed Control Room Design Review Program Plan for Perry Nuclear Power Plant (Units 1 and 2)" December 23, 1983.

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PERRY NUCLEAR POWER PLANT
UNIT 1

HED/APPENDIX CROSS REFERENCE

HED	APPENDIX	HED	APPENDIX
1	B	47	A
2	C	48	A
3	B	49	B
4	B	50	B
5	B	51	B
6	A	52	B
7	B	53	B
8	B	54	C
9	B	55	B
10	B	56	B
11	A	57	B
12	B	58	A
13	B	59	B
14	C	60	B
15	B	61	B
16	B	62	B
17	A	63	B
18	A	64	B
19	A	65	B
20	A	66	B
21	A	67	B
22	B	68	B
23	C	69	B
24	A	70	B
25	B	71	B
26	C	72	B
27	A	73	B
28	A	74	B
29	C	75	B
30	A	76	C
31	B	77	C
32	C	78	B
33	B	79	B
34	B	80	C
35	A	81	C
36	C	82	B
37	B	83	B
38	B	84	B
39	A	85	C
40	B	86	C
41	B	87	B
42	B	88	C
43	B	89	B
44	A	90	B
45	A	91	B
46	A	92	B

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HED/APPENDIX CROSS REFERENCE

HED	APPENDIX	HED	APPENDIX
93	B	143	B
94	B	144	B
95	C	145	B
96	C	146	B
97	A	147	B
98	B	148	B
99	A	149	A
100	C	150	B
101	B	151	B
102	B	152	B
103	B	153	B
104	C	154	B
105	B	155	B
106	B	156	B
107	B	157	B
108	A	158	B
109	B	159	B
110	B	160	B
111	B	161	B
112	B	162	B
113	B	163	B
114	B	164	B
115	B	165	B
116	B	166	B
117	B	167	B
118	A	168	B
119	B	169	C
120	B	170	B
121	A	171	B
122	B	172	B
123	B	173	B
124	B	174	B
125	B	175	B
126	B	176	B
127	B	177	B
128	C	178	B
129	B	179	C
130	B	180	C
131	B	181	B
132	B	182	B
133	B	183	C
134	B	184	B
135	C	185	C
136	B	186	A
137	B	187	A
138	C	188	C
139	B	189	B
140	B	190	A
141	B	191	A
142	B	192	A

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HED/APPENDIX CROSS REFERENCE

HED	APPENDIX
193	B
194	B
195	B
196	B
197	B
198	B
199	C
200	B
201	B
202	B
203	B
204	B
205	B
206	A
207	A
208	B
209	B
210	B
211	B
212	B
213	B
214	B
215	B
216	B
300	A
301	B
302	C
303	B
304	B
305	B
306	B
307	B
308	B
309	B
310	B
311	B
312	B
313	C
314	B
315	A
316	A
317	C
318	C
319	B
320	B
321	B
322	B
323	B
324	B
325	B
326	B
327	B
328	B
329	B
330	B
331	B
332	B
333	B
334	B
335	B
336	B
337	B
338	B
339	B
340	B
341	B
342	B
343	C
344	B
345	B
346	B
347	B
348	B
349	B
350	C
351	C
352	C
353	B
354	C
355	B
356	B
357	C
358	B
359	B
360	B
361	B
362	B
363	B
364	B
365	C
366	C
367	A
368	C
369	B
370	B
371	B
400	B
401	C
402	B
403	B

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HED/APPENDIX CROSS REFERENCE

HED	APPENDIX	HED	APPENDIX
404	B	1017	B
405	B	1018	B
406	B	1019	C
407	B	1020	B
408	B	1021	C
1001	B	1022	B
1002	B	1023	C
1003	B	1024	B
1004	B	1025	B
1005	B	1026	B
1006	C	1027	B
1007	B	1028	B
1008	A	1029	B
1009	C	1030	B
1010	B	1031	B
1011	B	1032	B
1012	C	1033	B
1013	B	1034	C
1014	B	1035	B
1015	B	1036	B
1016	A	1037	B

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PERRY NUCLEAR POWER PLANT
UNIT 1

APPENDIX A

Appendix A contains a list of 38 HEDs that are considered closed. These items were reviewed and evaluated by the NRC review team during the pre-implementation audit and no further action is required.

HED

6, 11, 17, 18, 19, 20, 21, 24, 27, 28, 30, 35, 39, 44, 45, 46, 47, 48, 58, 97, 99, 108, 118, 121, 149, 186, 187, 190, 191, 192, 206, 207, 300, 315, 316, 367, 1008, 1016

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APPENDIX B

Appendix B contains a list of 250 HEDs that are considered open pending implementation. These items were reviewed and evaluated by the NRC review team during the pre-implementation audit and it was determined that the proposed resolutions and implementations were satisfactory. All items must be implemented and verified per the schedule as stated on the HED Report Sheets. In the event an HED cannot be corrected as scheduled, the applicant will be required to provide a rationale for deferral and a schedule for completion that is acceptable to the NRC.

HED

1, 3, 4, 5, 7, 8, 9, 10, 12, 13, 15, 16, 22, 25, 31, 33, 34, 37, 38, 40, 41, 42, 43, 49, 50, 51, 52, 53, 55, 56, 57, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 78, 79, 82, 83, 84, 87, 89, 90, 91, 92, 93, 94, 95, 98, 101, 102, 103, 105, 106, 107, 109, 110, 111, 112, 113, 114, 115, 116, 117, 119, 120, 122, 123, 124, 125, 126, 127, 129, 130, 131, 132, 133, 134, 136, 137, 139, 140, 141, 142, 143, 144, 145, 146, 147, 148, 150, 151, 152, 153, 154, 155, 156, 157, 158, 159, 160, 161, 162, 163, 164, 165, 166, 167, 168, 170, 171, 172, 173, 174, 175, 176, 177, 178, 181, 182, 184, 189,

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193, 194, 195, 196, 197, 198, 200, 201, 202, 203, 204, 205, 208, 209, 210, 211, 212, 213, 214, 215, 216, 301, 303, 304, 305, 306, 307, 308, 309, 310, 311, 312, 314, 319, 320, 321, 322, 323, 324, 325, 326, 327, 328, 329, 330, 331, 332, 333, 334, 335, 336, 337, 338, 339, 340, 341, 342, 344, 345, 346, 347, 348, 349, 350, 353, 355, 356, 358, 359, 360, 361, 362, 363, 364, 365, 369, 370, 371, 400, 402, 403, 404, 405, 406, 407, 408, 1001, 1002, 1003, 1004, 1005, 1007, 1010, 1011, 1013, 1014, 1015, 1017, 1018, 1020, 1022, 1023, 1024, 1025, 1026, 1027, 1028, 1029, 1030, 1031, 1033, 1034, 1035, 1036, 1037.

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APPENDIX C

Appendix C contains a list of 46 HEDs that are considered open pending revised response, additional review, and implementation. For some, the condition of construction in the control room or the installation of these items at the time of the pre-implementation audit was not sufficiently finalized to permit a review. For others, a revised response or review is needed by CEI. All items must be evaluated, resolved, implemented, and verified with a schedule that is acceptable to the NRC.

HED	
2	Close on implementation and lighting survey to verify HED corrected and no new HEDs introduced. Survey results to be provided to the NRC with any new HEDs identified along with proposed corrections and implementation schedules.
14	Revised response to indicate I&C responsibility for storage and replacement of light bulbs, expendables, etc.
23	OK with possible exception of panel 623. Glare on vertical panels should be checked once temporary HVAC, etc. is removed. Diffusers on lights above vertical panels are less effective than those in control room horseshoe. Include in environmental surveys.

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26 Revised response for annunicator 680-1-16 to indicate additional information available and used by the operator to determine cause of the alarm. Revised response for annunciators 845-C7 and E8 to indicate how operator determines cause of the alarm (TRAIN A/E).

29 Revised response to indicate finalized list of first and second priority alarms.

32 Revised response on f and g.

36 Revised response to indicate whether inactive points will light anytime other than when tested.

54 Check PNPP HUMAN FACTORS CONTROL ROOM STANDARDS for completeness. CR2940's and SBM's can have several types of handles. Standard doesn't indicate keyswitch applications, J-handles, oval handles, push buttons with rotary collars, etc.

76 Describe how "where applicable" is determined for this and other HEDs for which such a decision is to be made.

77 Needs category assignment if full correction is to be delayed until prior to startup after first refueling outage.

80,81 OK if based on PNPP HUMAN FACTORS CONTROL ROOM STANDARD. Need revised response.

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85 OK except for amber and blue single lamp indicators. Need revised response to address.

86 OK except for amber and blue single lamp indicators. Need revised response to address.

88 Who does this and what tools are available? Need revised response.

96 Need revised response to indicate labeling.

100 Not evaluated. Pre-implementation audit team indicated concern about use of color banding techniques with color indication used on recorder meters. Need details of finally selected and verified correction.

104 Provide list of recorders not covered by ERIS and recorders which give trends of greater than 15 minutes.

128 Revised response needed to indicate how controllers will be labeled on all panels including the vertical panels.

135 Not OK. Use of "ALRM" for alarm is not consistent with the PNPP HUMAN FACTORS CONTROL ROOM STANDARDS.

138 Not OK. Proposed correction uses "COND" as abbreviation for condenser. PNPP HUMAN FACTORS CONTROL ROOM STANDARDS indicate abbreviation for condenser is CNDR.

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169 Color convention upgrade. Revise PNPP HUMAN FACTORS CONTROL ROOM STANDARDS to include red demarcation lines and color padding.

179 A revised response indicating that, e.g. "Each alarm must be individually acknowledged" would clarify the resolution of the HED.

180 Perform a human factors review of additions to Perry standard abbreviations to prevent conflicts and possible misunderstandings.

183 Revised response to indicate use of QAP-1702 when completed, approved, and implemented.

185 Revised response indicating administrative procedures for periodic maintenance (calibration and convergence).

188 Review of color standards ERIS/process computer vs. control room identifying potential problems, assess and correct if warranted.

199 Revised response to indicate in detail, how the operator determines water level under accident conditions using control room instrumentation and/or ERIS.

302 Review to assure HED is corrected and no new HEDs introduced.

313 Review to determine whether turbine eccentricity, speed, and valve position all need to be displayed on the subject recorder.

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317 Revised response. Consider reduced lighting in control room.

318 OK if potentiometer with on-off switch, but verify proper indication of switch on-off so that operators are aware alarm has been turned off or reduced in volume.

343 Review adequacy of input to ERIS for determining CST level.

351 Revise response to include emergency equipment storage.

352 Verify existence of an administrative procedure on housekeeping or provide revised response.

354 Revised response to indicate slippage of final correction to prior to end of first refueling outage. Indicate interim fix. Provide list of all "OPEN-CLOSE" controllers and indicate which will be corrected. Justify those not corrected.

357 OK but revise convention to indicate "special case" use of oval instead of J-handles.

366 Conduct sound survey in completed control room and provide results to NRC. Identify any HEDs along with proposed corrections and implementation schedules.

368 Verify ability to communicate while performing control room tasks in breathing equipment.

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401 Revised response to indicate actual resolution of HED.

1006 Revised response to indicate whether dedicated channel is incoming or outgoing.

1009 Revised response to indicate final resolution.

1012 Consider use of 3-position switch for B33-F019 and B33-F020 to be consistent with rest of control room.

1019 Revised response to indicate how operators will keep track of the situation, inform the new shift, etc.

1021 Revised response to clarify position of hydrogen analyzers and annunciators and to clarify modification.

1032 Revised response on item 1. Item 2 OK.

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PERRY NUCLEAR POWER PLANT

UNIT 1

APPENDIX D

Several recommendations resulted from the NRC staff's evaluation of the PNPP DCRDR. The recommendations are not intended as additional requirements, but they are intended to encourage the fullest possible benefit from the DCRDR. Although some changes to the current process of the DCRDR may be necessary to follow the recommendations, the benefit should easily justify the effort. The recommendations are:

1. Recommend that labels on pushbuttons on HOTWELL LEVEL CONTROLLER (Panel 870-2) be changed from "CLOSE - OPEN" to something which more clearly reflects the actual change in plant condition (e.g., "LOWER LVL - RAISE LVL")

2. Recommend shortening the ends of the rails on panels 680, 870, and 601 so that they do not project out as far as the ends of the panels to reduce the likelihood of snagging.

3. Recommend specific training of operators with respect to the resolution of HED 27 as well as detailed coverage in the Annunciator Response Instructions

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4. Recommend that the PNPP HUMAN FACTORS CONTROL ROOM STANDARDS be upgraded to include various handle types and that the control room then be upgraded to the standards

5. Recommended enhancement of position markings on rotary collars so that operators can quickly discern collar position (e.g., MANUAL SCRAM BUTTONS on Panel 680)

6. Recommend investigating use of hierarachical labeling with the proposed demarcation around MANUAL SCRAM and MANUAL ISOLATION pushbuttons on Panel 680

7. Recommend RFP and MFP flow indicators on Panel 680-3B be made consistent (i.e., both to have same scale multiplier) prior to fuel load to minimize negative transfer of training

8. Recommend careful monitoring of implemented corrections to assure they are as specified and work with other corrections

9. Recommend removal of "CONTROL VALVE POSITION" from face of N27-12546 A&B as unnecessary information

10. Recommend use of hierarchical labeling on vertical panels (with demarcation where demarcation is used)

11. Recommend Bailey Control Station lights (green "A", yellow "M") be changed to conform to the PNPP HUMAN FACTORS CONTROL ROOM STANDARDS

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12. Recommend design of labels on back row of "C" inserts on Panel 680 (e.g., MANUAL SCRAM SWITCHES) be modified (e.g., enlarged) to reduce obscuration of position information (i.e., position indicators for rotary collars)

13. Recommend review of mimics to determine whether additional start and end point information would aid the operator's memory of system operation, particularly on vertical panels

14. Recommend review of mimics to determine whether additional engraved flow arrows would aid the operator's memory of system operation (e.g., flow can be either direction in part of the RHR system depending on valve alignment - double ended arrows may be useful in that portion of mimic)

15. Recommend mimic symbols (arrows, pumps, etc.) be included in the PNPP HUMAN FACTORS CONTROL ROOM STANDARDS

16. Recommend that computer keys be designed so that dirt does not impair the readability of the information on them

17. Recommend enhancement aid on Division 3 WIDE RANGE AND FUEL ZONE REACTOR WATER LEVEL INDICATING RECORDER on Panel 601-2B to increase the operator's ability to acquire necessary information while operating in the HPCS area

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18. Recommend review of annunciator readability from annunciator control stations, especially on vertical panels

19. Recommend additon of "scribble plates" so the operator can denote what parameters have been selected for display on the three digital displays for computer output on Panel 680

20. Recommend review of all the different uses for amber and reduction of that number

21. Recommend color banding of meters associated with "HI/LO" annunciators to aid quick recognition of whether parameter is HI or LO

22. Recommend that consistency of labeling between annunciators and displays be confirmed (e.g., the HPCS DAY TANK LEVEL HIGH/LOW annunciator and the FUEL DAY TANK LEVEL display on Panel 601-16 refer to the same tank using different terms)

23. Recommend that consistency between control room, DCRDR Summary Report, and drawings be confirmed:

a. e.g., Summary Report indicates annunciator 601-20-D5 should read "RCIC & RHR ST & SHTDN ISOL RHR RM A/B HOT" while the drawing indicates that it should read "RCIC & RHR ISOL RHR RM A/B TEMP HIGH"

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b. e.g., Drawing indicates that annunciator 680-1-A1 should read "RWCU F/D INLET COND HI/FAILED" while the actual tile reads "RWCU F/D IN CONDUCTIVITY HIGH/FAILED"

(information provided during the pre-implementation audit indicated the drawing was correct in example 1 and the panel was correct in example 2)

24. Recommend that PNPP HUMAN FACTORS CONTROL ROOM STANDARDS be revised to incude PSID if that abbreviation is used in the control room

25. Recommend scheduled check (e.g., daily) of printer paper and ribbons, recorder paper and ink, etc. to assure that I&C technicians can be notified of service needs in a timely manner

26. Recommend that an administrative procedure addressing coordination between the control room and computer room be developed (specifically addressing timely provision to the control room of any output directed to the backup printer in the computer room when the control room printer is out-of-service)

27. Recommend that resets and indicators in the control room be reviewed for consistency of operator interface (e.g., B33A-S110 is not consistent with other RCIRC system reset indication). Further recommend that consistent approach be developed, documented in the PNPP HUMAN FACTORS CONTROL ROOM STANDARDS, and implemented in the control room

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28. Recommend FDW A/B PRESS and RX PRESS on Panel 680-3 be scaled the same. FDW A/B PRESS are scaled 0-150 x 10 while RX PRESS is scaled 0-1200. The values are to be compared

29. Recommend consideration be given to removing from the control room any displays or controls identified during the DCRDR as not required

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APPENDIX Q

PERRY NUCLEAR POWER PLANT UNIT 1
SAFETY EVALUATION REPORT SUPPLEMENT:

PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

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APPENDIX Q

PERRY NUCLEAR POWER PLANT UNIT 1
SAFETY EVALUATION REPORT SUPPLEMENT:

PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

I. INTRODUCTION

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permit was issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice examination requirements set forth in editions and addenda of Section XI of the ASME Boiler and Pressure Vessel Code applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In a letter dated June 3, 1985 (M. R. Edelman to B. J. Youngblood), the applicant requested relief from ASME Code Section XI requirements which the applicant has determined are not practical and provided supporting information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing the applicant's submittals to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements was justified.

II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for Perry Nuclear Power Plant Unit 1 was issued on May 3, 1977. In accordance with 10 CFR 50.55a(g)(3), components (including supports), which are classified as ASME Code Class 1 and 2, have been designed and provided with access to enable the performance of required preservice examinations.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically examined (radiographed) and the system was subjected to hydrostatic pressure tests.

C. The intent of a preservice examination is to establish a reference or baseline before the initial operation of the facility. The results

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of subsequent inservice examination can then be compared with the original condition to determine whether changes have occurred. If the inservice inspection results show no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of preservice examination also demonstrates that the welds so examined are capable for subsequent inservice examination using a similar test method.

In the case of Perry Nuclear Power Plant Unit 1, a large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The performance of supplemental examination, such as surface examination, in areas where volumetric examination is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

Several of the preservice inspection relief requests involve limitations to the examination of the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic service-induced degradation. In the event that the welds identified in the preservice inspection (PSI) relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

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III. EVALUATION OF RELIEF REQUESTS

The applicant requested relief from the specific PSI requirements in a letter dated June 3, 1985 (M. R. Edelman to B. J. Youngblood). On the basis of the information submitted by the applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice inspection requirements of the ASME Boiler and Pressure Vessel Code, Section XI have been determined to be impractical to perform. The applicant has demonstrated that either (1) the proposed alternative would provide an acceptable level of quality and safety or (2) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a (a)(3), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1977 Edition including addenda through Summer 1978.

A. Relief Request #1, Category B-A, Pressure-Retaining Welds in the Reactor Vessel, Category B-D, Reactor Vessel Nozzle Welds, and Category B-F, Reactor Vessel Safe End Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-A requires a 100% volumetric examination of the pressure retaining welds in the reactor pressure vessel (RPV).

Examination Category B-D requires a 100% volumetric examination of the RPV nozzle-to-vessel welds and of the nozzle inside radius section. Examination Category B-F requires a 100% volumetric and surface examination of the RPV nozzle-to-safe end welds.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the subject areas identified in the June 3, 1985 submittal of Relief Request #1.

Reason for Request: The design of the RPV includes nozzles, lifting lugs, and other geometry constraints that prevent a 100% ultrasonic examination of the subject RPV nozzles and welds.

The applicant states that the preservice structural integrity of the RPV welds was demonstrated during construction by meeting the examination and hydrostatic test requirements of ASME Code Section III, and that weld techniques and welders were qualified in accordance with Code requirements and materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: The staff has reviewed the June 3, 1985 submittal including the table identifying the welds for which relief is being requested. This table lists the weld number, type of weld, Code examination category, the specific reason each examination was limited (i.e., nozzle obstruction, weld geometry, control rod drive (CRD) interference, etc.), and the applicant's estimate of the Code-required examination that was completed. On the basis of this review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that the reactor vessel would have to be redesigned in order to complete the remainder.

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Complete examinations meeting the requirements of ASME Code Section XI were performed on welds on similar configurations which utilized the same weld techniques, procedures, and materials. The inspected welds will be subject to the same operating and environmental conditions as the partially inspected or uninspected welds. Therefore, the acceptable preservice examination results on the inspectable welds provide reasonable assurance by sampling of the structural integrity of the partially inspected or uninspected welds.

On the basis of the above, the staff has concluded that the limited Section XI volumetric examinations and the Section III fabricated examinations provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties a compensating increase in the level of quality and safety.

B. Relief Request #2, Category B-G-1, Item B6.40, Ligaments Between Stud Holes

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-G-1, Item B6.40, requires a 100% volumetric examination of the ligaments between stud holes in the RPV.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the 72 stud hole ligaments or the RPV.

Reason for Request: Volumetric examination of the stud hole ligament area was limited by the lip of the flange seal surface. The limitation was approximately 7% of the total required area for each stud hole ligament.

Staff Evaluation: When defining the requirements for the preservice examination of welds in Class 1 components in paragraph IWB-2200, "Preservice Examination," the Code uses the terminology "to include essentially 100% of the pressure retaining welds." The applicant's request involves the volumetric examination of base materials and the stud hole threads. The staff interprets the corresponding Code requirement to mean "essentially 100%" of base material when only machined surfaces are required to be examined. The staff's interpretation is supported by the Code Figure IWB-2500-4, which defines the required extent of volumetric examination of threads in base materials and ligaments between stud holes. The applicable code figures show a designed geometric discontinuity, e.g. either the flange face or the flange sealing surface, that would prevent the volumetric examination of a small segment of the ligament between stud holes.

The applicant has performed a preservice examination of approximately 93% of each stud hole ligament area and the remainder of the examination was limited by the lip of the flange seal surface. The staff concludes that the applicant has met the Code requirement of examining "essentially" 100% of the volume defined in Figure IWB-2500-4 and, therefore, relief is not required.

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C. Relief Request #3, Category B-G-1, Reactor Recirculation Pump Bolts and Studs

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-G-1, Item B6.180 requires a 100% volumetric examination of pump bolts and studs larger than 2 inches in diameter.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on 16 reactor recirculation pump studs.

Reason for Request: Volumetric examination of the reactor recirculation pump studs was limited by the elongation measurement hole. The limitation was approximately 22% of the total required volume.

The applicant states that the structural integrity of the recirculation pump bolting was demonstrated during construction by meeting the requirements of ASME Code Section III, and that materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines. The material in other inspected areas is identical to the non-inspected portion of the studs. Since the construction, operating conditions and environmental conditions on the non-inspected portions will be identical to the inspected area, it is reasonable to extend the satisfactory examination results to the non-inspected areas. Finally, the pressure boundary received the required hydrostatic test.

Staff Evaluation:

The staff has determined that compliance with the Code requirement is impractical because of the existing design of the stud, with the elongation measurement hole, limits the inspection of approximately 22% of the total volume required to be examined. However, the thread root area received a 100% inspection and this is the major area of interest during the preservice examination. Each of the studs received a preservice liquid penetrant examination. Therefore, the staff concludes that the limited Section XI volumetric examination and the Section III fabrication requirements and hydrostatic test provide an acceptable level of preservice structural integrity.

Inservice degradation of threaded fasteners has been detected with a combination of the examination methods used by the applicant during fabrication and the preservice examination. Successful inservice inspection programs for preventing service-induced failures have included periodic visual examinations of the fastener for evidence of flange leakage and effective volumetric examination of the thread root area with procedures capable of detecting cracks. In addition, when the fasteners were removed a liquid penetrant examination of the threaded area was performed. During the preparation of the ISI Program, the applicant should consider available alternative inspection methods to supplement the limited volumetric inservice examination.

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D. Relief Request #4 Category B-G-2, Control Rod Drive Housing (CRDH) Flange Bolts

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-G-2, Item B7.10, requires a visual (VT-1) examination of pressure-retaining bolting 2 inches and smaller in diameter.

Code Relief Request: Relief is requested from performing the entire Code-required VT-1 examination.

Reason for Request: Access to the control rod drive housing (CRDH) flange bolts is obstructed by the surrounding CRDH tubes. Complete examinations meeting the requirements of ASME Code Section XI were performed on the outer periphery CRDH flange bolting of the same configuration.

The applicant states that the preservice structural integrity of the CRDH pressure boundary was demonstrated during construction by meeting the examination and hydrostatic test requirements of ASME Code Section III, and that materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines. The inspected CRDH flange bolting will be subject to the same operating environmental conditions as the uninspected CRDH flange bolting. It is, therefore, reasonable to extend the acceptable results on the inspectable CRDH flange bolting to the uninspectable CRDH flange bolting.

Staff Evaluation: The Code defines the purpose of the VT-1 visual examination "to determine the condition of part, component, or surface examined, including such conditions as cracks, wear, corrosion, erosion, or physical damage on the surfaces of the part or components." The VT-1 visual examination may be conducted directly when access is sufficient to place the eye within 24 inches of the surface to be examined and at an angle not less than 30 degrees to the surface. Mirrors may be used to improve the angle of vision. Lighting, natural or artificial, shall be sufficient to resolve a 1/32-inch black line on an 18% neutral gray card. Remote VT-1 visual examination may be substituted for direct examination. Remote examination may use aids such as telescopes, borescopes, fiber optics, cameras, or other suitable instruments, provided such systems have a resolution capability at least equivalent to that attainable by direct visual examination.

The staff has determined that the inspections and dimensional tolerance measurements, conducted on all of the CRDH flange bolts during fabrication and installation, are equivalent or superior to the Code-required VT-1 visual examination of the assembled flange. The staff, therefore, concludes that the inspections conducted during fabrication and installation are an acceptable alternative to the preservice visual examination required by the Code and provide an acceptable level of quality and safety.

E. Relief Request #5, #6, #17, and #18, Categories B-J and C-F, Class 1 and Class 2 Pressure-Retaining Welds in Piping

Code Requirements: Section XI, Table IWB-2500-1, Examinaton Category B-J, Item B9.10, requires a 100% surface and volumetric examination of Class 1 pressure retaining welds on piping 4 inches in diameter and larger.

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Section XI, Table IWC-2500-1, Examination Category C-F, Item C5.20 requires a 100% surface and volumetric examination of Class 2 pressure retaining welds over 1/2-inch nominal wall thickness.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the 74 Category B-J and C-F welds identified in the June 3, 1985 submittal of Relief Requests #5, #17, and #18.

Relief is requested from performing 100% of the Code-required volumetric examination on the 26 welds with corrosion resistant cladding identified in the June 3, 1985 submittal of Relief Request #6.

Reason for Request: For Relief Requests #5, #17, and #18, because of the configuration of these welds (pipe-to-fitting, fitting-to-fitting, fitting seams, or permanently welded attachments) the volumetric examination can not be performed on 100% of the Code-required weld volume. The accessible portion of these welds were volumetrically examined in accordance with Section XI requirements. The one weld listed in Relief Request #18 was completely inaccessible because of obstruction by a permanent hanger. The applicant estimated that the other 73 welds listed received volumetric examination average over 70% of the Code-required volume.

For Relief Request #6, because of the configuration of these welds (pipe-to-fitting with corrosion resistant cladding both inlayed and overlayed) the volumetric examination cannot be performed on 100% of the Code-required weld volume. Typical techniques identified in Appendix III of Section XI proved to be ineffective. To overcome the metallurgical properties impeding conventional shear wave ultrasonic transmission, refracted longitudinal wave examinations were employed. The acoustic properties of refracted longitudinal wave propagation limit the technique to 1/2 V path (see discussion in Section 5.2.5.2 of this supplement). The Code-required volume necessitates a full V path through the weld and required volume. Therefore, when access to a butt weld was limited to one side only by component geometry (e.g., pipe-to-valve) the perpendicular examination is considered to be only 50% complete. The accessible portions of these welds were volumetrically examined in accordance with Section XI requirements. Twenty-two welds received 50% coverage, one weld received approximately 85% coverage, and three welds received 95% or greater coverage. In addition, these welds received the Section XI Code-required surface examination.

The applicant states that the preservice integrity of the piping pressure boundary was demonstrated during construction by meeting the examination and hydrostatic test requirements of ASME Code Section III, and that weld techniques and welders were qualified in accordance with Code requirements and materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: The staff has reviewed the June 3, 1985 submittal including the tables identifying the welds for which relief is being requested. These tables list the weld number, system, configuration (pipe-to-fitting, nozzle-to-flange, fitting-to-valve, etc.), nature of obstruction (permanent hangers, lugs, branch connections, corrosion-resistant cladding, etc.), and the applicant's estimate of the percentage of the Code-required examination that was completed.

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Complete examinations meetings the requirements of ASME Code Section XI were performed on welds of similar configurations which utilized the same weld techniques, procedures, and materials. The inspected welds will be subject to the same operating and environmental conditions as the partially inspected welds or the uninspected weld. Therefore, the acceptable preservice examination results of the inspectable welds provide reasonable assurance by sampling of the structural integrity of the subject welds.

On the basis of the above, the staff has concluded that the limited Section XI volumetric examination and the Section III fabrication examinations provide an acceptance level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

F. Relief Requests #7, #15, and #16, Categories B-J and C-F, Class 1 and Class 2 Pressure-Retaining Welds in Piping, and

Relief Requests #8 and #14, Categories B-K-1 and C-C, Class 1 and Class 2 Integrally Welded Support Attachments

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-J, Items B9.10 and B9.20, require a 100% surface and volumetric examination of Class 1 pressure-retaining welds on piping of 4-inch diameter and larger and a 100% surface examination of Class 1 pressure-retaining welds on piping less than 4 inches in diameter.

Section XI, Table IWC-2500-1, Examination Category C-F, Items C5.10 and C5.20, require a 100% surface and volumetric examination of Class 2 pressure-retaining welds on piping with greater than 1/2 inch nominal wall thickness and 100% surface examination of Class 2 pressure-retaining welds on piping with 1/2 inch or less nominal wall thickness.

Section XI, Table IWB-2500-1, Examination Category B-K-1, Item B10.10, requires a surface examination for Class 1 integral welded supports and Table IWC-2500-1, Examination Category C-C, Items C3.10 and C3.40, require a surface examination for Class 2 integral welded supports whose base material design thickness exceeds 1/2 inch for vessels and 3/4 inch for piping.

Code Relief Request: Relief is requested from performing 100% of the Code-required surface examination on the 23 pressure-retaining welds listed in the June 3, 1985, submittal of Relief Requests #7, #15, and #16, and 22 integrally welded support attachments of Relief Requests #8 and #14.

Reason for Request: Because of lugs, branch connections, permanent hangers, or other obstructions, the surface examination cannot be performed on 100% of the Code-required surface. The two welds listed in Relief Request #15 received no surface examination because of permanent hangers obstructing the examination area. The remaining 21 welds listed in Relief Requests #7 and #16 received surface examinations on the accessible portion of the welds (13 received 90% or more of the Code-required surface examination).

For the integrally welded support attachments addressed by Relief Requests #8 and #14, seven of the attachments received 90% or more of the

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Code-required surface examination and six attachments were totally obstructed. More than half of the required surface was examined on the remaining nine attachments.

The applicant stated that the preservice structural integrity of the piping pressure boundary and attachments was demonstrated during construction by meeting the examination and hydrostatic test requirements of ASME Code Section III, and that weld techniques and welders were qualified in accordance with Code requirements and materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: The staff has reviewed the June 3, 1985 submittal including the tables identifying the welds for which relief is being requested. These tables list the weld number, system, configuration (pipe-to-fitting, fitting seam welds, etc.), nature of obstruction (permanent hangers, lugs, branch connections), and the applicant's estimate of the percentage of the Code-required examination that was completed.

The Code defines the purpose of a surface examination to indicate "the presence of surface cracks or discontinuities. It may be conducted by either a magnetic particle or a liquid penetrant method where the surface condition, material, and accessibility permit such an examination." The Code also permits the substitution of shop and field examinations for the onsite preservice examinations provided:

(1) in the case of vessels only, the examination is performed after the hydrostatic test required by Section III has been completed

(2) such examinations are conducted under conditions and with equipment and techniques equivalent to those that are expected to be employed for subsequent inservice examinations

(3) the shop and field examination records are, or can be, documented and identified in a form consistent with those required in IWA-6000

Most utilities elect to perform separate preservice examinations instead of exercising the Code option of substituting shop and field examinations. The records of the preservice examination provide a baseline for future examinations and identify the limitations to examination resulting from the construction of adjacent components. The staff has reviewed the weld configurations identified by the applicant in these relief requests and determined that the construction Code requires at least one surface examination during fabrication of most if not all of the welds. In addition, a preservice and construction Code volumetric examination was performed on most of the pressure-retaining piping welds identified in Relief Requests #7, #15 and #16. Therefore, the staff concludes that the Section III fabrication examinations and the hydrostatic test, supplemented by the limited Section XI surface examination and volumetric examination, where required, are equivalent or superior to the required preservice surface examination and these examinations and tests provide an acceptable level of quality and safety.

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G. Relief Requests #9, #19, and #20, Categories B-M-1 and C-G, Valve Body and Pump Casing Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-M-1, Item B12.30 requires a volumetric and surface examination of Class 1 valve body welds.

Section XI, Table IWC-2500-1, Examination Category C-G, Items C6.10 and C6.20, require a surface examination of Class 2 valve body and pump casing welds.

Code Relief Request: Relief is required from performing the Code-required surface or volumetric examination on the 20 valve body welds and 13 pump casing welds listed in the July 3, 1985, submittal of Relief Requests #9, #19, and #20.

Reason for Request: The 20 valve body welds listed in Relief Requests #9 and #20 are partially inaccessible because of Code Plates. All 20 of these welds received 89% to 98% of the Code-required examination(s). The 13 pump casing welds listed in Relief Request #19 did not receive surface examination because the pump barrel is located below floor-level, making the welds inaccessible.

The applicant states that (1) the preservice structural integrity of the valve and pump pressure boundaries were demonstrated during construction by meeting the examination and hydrostatic test requirements of ASME Code Section III, (2) weld techniques and welders were qualified in accordance with Code requirements, and (3) materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: The staff has reviewed the June 3, 1985 submittal including the tables identifying the valve body and pump casing welds for which relief is being requested. These tables list the valve or pump weld number, system, configuration (i.e, pump head-to-shell weld, valve body weld), nature of obstruction, (i.e., code plate, below floor level) and the applicant's estimate of the percentage of the Code-required examination that was completed.

On the basis of the above, the staff has determined that the Section XI preservice examinations were essentially completed on the valve body welds described in Relief Requests #9 and #20 and, therefore, relief is not required.

The construction Code requires at least one surface examination during fabrication of most if not all of the pump casing welds described in Relief Request #19. The staff, therefore, concludes that the construction Code examinations and the hydrostatic test provide an acceptable level of quality and safety. However, in the event that the pumps are disassembled for inservice repair or maintenance, so that the subject pump welds are accessible, the staff will require that the preservice inspection be performed at that time.

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H. Relief Request #10, Category B-L-2 and B-M-2, Pump Casings and Valve Bodies

Code Requirement: Section XI, Table IWB-2500-1, Examination Categories B-L-2 and B-M-2, Items B12.20 and B12.40 require visual (VT-1) examinations of the internal surfaces of certain pump casings and valve bodies.
Code Relief Request: Relief is requested from having VT-1 certified personnel performing the examinations on the 20 valve bodies, and 1 pump casing listed in the June 3, 1985 submittal of Relief Request #10.

Reason for Request: Receiving inspection of these components were performed by ANSI N45.2.6 mechanical certified personnel with procedures and records similar to VT-1 requirements.

Staff Evaluation: The subject pump casings and valve bodies were volumetrically examined by radiography and hydrostatically tested in accordance with ASME Code Section III requirements. The staff has determined that disassembly of pumps and valves at this time, for the sole purpose of performing preservice visual examination using qualified personnel, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The staff has concluded that the construction code examinations and tests exceed the requirements for visual examination and, therefore, are an acceptable alternative to the Section XI preservice visual examination.

I. Relief Request #11, Category B-O, Control Rod Drive Housing Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-O, Item B14.10 requires a surface or volumetric examination on the peripheral CRDH welds.

Code Relief Request: Relief is request from performing 100% of the required surface examination because of partial inaccessibility of the examination area.

Reason for Request: A total 360° surface examination cannot be accomplished because of interference from adjacent CRDHs. The subject welds did receive 85% of the Code-required surface examination.

The applicant states that the preservice structural integrity of the CRDH welds was demonstrated during construction by meeting the examination and hydrostatic test requirements of ASME Code Section III, and that weld techniques and welders were qualified in accordance with Code requirements and materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: The staff concludes that requiring the removal of the installed CRD support structure to perform the required surface examination would result in hardships and unusual difficulties without a compensating increase in the level of quality and safety because the fabrication examinations and the hydrostatic test are equivalent or superior to the required preservice inspection. In the event that the CRDHs are disassembled for inservice repair or maintenance, such that the subject welds are accessible, the staff will require that the preservice inspection be performed at that time.

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J. Relief Request #12, Category C-A, RHR Heat Exchanger Pressure Retaining Weld

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-A, Item C1.10, requires a 100% volumetric examination of the subject residual heat removal (RHR) heat exchanger shell weld.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on weld 1-E12-B001A-003.

Reason for Request: Seismic lugs limit the ultrasonic examination of the weld and required volume to 43% in the axial direction.

The applicant states that the preservice structural integrity of the heat exchanger shell welds was demonstrated during construction by meeting the radiographic and hydrostatic test requirements of ASME Code Section III, and that weld techniques and welders were qualified in accordance with Code requirements and materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: Since the construction, operating conditions, and environmental conditions on the noninspected portion of the weld are identical to the inspected area, the acceptable preservice examination results provide reasonable assurance by sampling of the structural integrity of the noninspected area. The staff, therefore, concludes the limited Section XI volumetric examination, and the Section III fabrication examinations performed during construction are acceptable alternatives for PSI and provide an acceptable level of quality and safety.

K. Relief Request #13, Category C-B, RHR Heat Exchanger Inlet Nozzle Welds

Code Requirements: Section XI, Table IWC-2500-1, Examination Category C-B, Item C2.20 requires a 100% surface and volumetric examination of nozzles in vessels over 1/2-inch nominal wall thickness.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following welds:

1-E12-B001A-004
1-E12-B001B-004
1-E12-B001C-004
1-E12-B001D-004

Reason for Request: Instrument lines limit ultrasonic examination of the welds to 95.5% of the Code-required volume.

The applicant states that the preservice structural integrity of the heat exchanger nozzle welds was demonstrated during construction by meeting the radiographic and hydrostatic test requirements of ASME Code Section III, and that weld techniques and welders were qualified in accordance with Code requirements and materials were purchased and traced in accordance with the appropriate Code and NRC requirements and guidelines.

Staff Evaluation: The staff has determined that the Code-required preservice examination was essentially completed on these welds and, therefore, relief is not required.

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IV. CONCLUSIONS

On the basis of the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI required preservice examinations are impractical. The applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing Perry Nuclear Power Plant Unit 1 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI-required examinations would delay startup of the plant so that a significant number of plant systems could be redesigned, sufficient replacement components could be obtained, the new components could be installed, and the preservice examination of these components could be repeated. Examples of components that would require redesign to meet the specific preservice examination provisions are: the reactor pressure vessel, RHR heat exchanger, and a significant number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

On the basis of the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

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14 ABSTRACT (200 words or less)

This Supplement, No. 7, reports the status of certain issues that had not been resolved at the time of publication of the Safety Evaluation and Supplement Nos. 1 through 6 to that report.

The Perry Nuclear Power Plant facility is located in Lake County, Ohio, approximately 35 miles northeast of Cleveland, Ohio.

This report relates to the application for licenses to operate the Perry Nuclear Power Plant, Units 1 and 2 filed by the Cleveland Electric Illuminating Company on behalf of itself and as agent for the Duquesne Light Company, the Ohio Edison Company, the Pennsylvania Power Company and the Toledo Edison Company as applicants and owners.

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